

2006 California Gas Report

Prepared by the California Gas and Electric Utilities

2006 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS UTILITIES

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2006 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2006 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2025. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission Decision D.95-01-039. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

The report is organized into three sections: Executive Summary, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Northern California section provides detail on requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), Wild Goose Storage, Inc. and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Municipal Oil and Gas Department, San Diego Gas and Electric Company, and the City of Los Angeles Department of Water and Power.

Each participating utility has provided a narrative explaining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables showing data on natural gas requirements (demand) by customer class. Separate sets of these tables are presented for average and cold year temperature conditions. Any forecast, however, is subject to considerable uncertainty. Changes in the economy, energy and environmental policies, natural resource availability, and the continually evolving restructuring of the gas and electric industries can significantly affect the reliability of these forecasts. This report should not be used by readers as a substitute for a full, detailed analysis of their own specific energy requirements.

A working committee, comprised of the representatives from each utility was responsible for compiling the report. The membership of this Committee is listed in the Respondents section at the end of this report.

2006 CALIFORNIA GAS REPORT

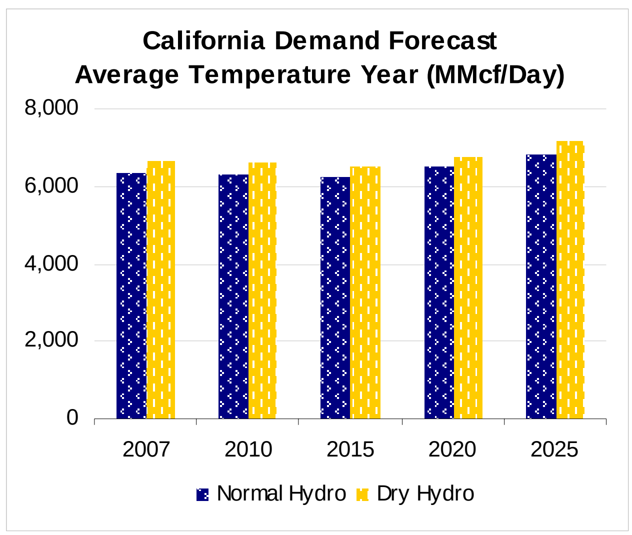
EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

DEMAND OUTLOOK

California natural gas demand, including volumes not served by utility systems, is expected to grow at an annual average rate of 0.5 percent from 2006 to 2025. Forecast growth is a combination of anticipated growth in the electric generation (EG) market segment tempered by slower growth in the residential and commercial markets and virtually no growth in the industrial sector.

EG gas demand is expected to increase at an annual average rate of 1.8 percent based on the assumption that gas-fired generation continues to be the technology of choice to meet the ever-growing demand for electric power. Residential and commercial sector consumption is expected to increase by an average of 0.4 percent per year over the forecast period. Demand in the industrial sector is estimated to decline by 0.4 percent annually as California continues its transition from a manufacturing-based to a service-based economy.



Under normal temperature conditions and a normal hydropower (hydro) year, gas demand for the state is projected to average 6,150 MMcf/d in 2006 increasing to 6,693 MMcf/d by 2025, a cumulative growth of 8.8 percent during the forecast period. Gas demand is expected to be 5% higher under the combined scenario of temperature conditions and a low hydro year. Northern California is projected to show a larger load increase than Southern California under the combined normal temperature conditions and low hydro year scenario, since northern California tends to rely more heavily on hydroelectric power than Southern California. The graph on the right shows statewide demand for an average temperature year under normal hydro and low hydro years.

FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency (CEE) and other Demand-Side Management (DSM) programs in their utility electric and gas resource plans. The 2000-2001 “energy crisis” in California was not limited to electricity, with gas prices at the southern California border reaching levels nearly ten times greater than experienced in recent history. California utilities are committed to helping their customers make the best possible choices regarding use of this increasingly valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC-mandated goals for renewable power generation and electric energy efficiency programs.

The table below approximates total gas savings based on the impact of renewables, electric and gas energy efficiency goals on CPUC-jurisdictional utilities. Gas savings from electric energy efficiency goals are based on a generic assumption of heat rate per megawatt hour of electricity produced at gas-fired peaking and combined-cycle power plants.

Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand

Year	2006	2010	2015	2020	2025
California Energy Requirements by CPUC-Jurisdictional Utilities (1)					
Electricity Demand (GWh)	277,652	293,310	311,136	328,641	347,254
20% Renewables Goal for 2010					
Renewable Electric Generation (GWh/Yr) (2)	30,793	58,662	62,227	65,728	69,451
Increase over 2005 Level (GWh/Yr) (3)	6,967	34,836	38,401	41,902	45,625
Gas Savings over 2005 Level (Bcf/Yr)	44	218	240	262	285
Electric Energy Efficiency Goals (4)					
Electricity Savings over 2005 Level (GWh/Yr)	5,200	15,914	25,752	25,752	25,752
Gas Savings over 2005 Level (Bcf/Yr)	33	99	161	161	161
Energy Efficiency Goal for Natural Gas Programs (4)					
Gas Savings over 2005 Level (Bcf/Yr)	5	16	43	70	87
Total Gas Savings (Bcf/Yr) (5)	82	333	444	493	533

Note:

(1) Electricity demand based on *California Energy Demand 2006-2016 – Staff Energy Demand Forecast*, CEC-400-2005-034-SD, June 2005. Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year (24 * 365), and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approx. 10,000 CF) of natural gas. Each MWh displaced from a

combined-cycle plant saves 7 MMBtu (7 Dth, or approx. 7000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,760 hours * 10% * 10 MMBtu, plus 8,760 hours * 75% * 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods produce greater natural gas savings per MWh. Similar estimates apply to renewable electric generators.

(2) Renewables goal for 2006 is the sum of actual renewables in 2005 of 23,885 GWh (Source: http://www.cpuc.ca.gov/static/energy/electric/renewableenergy/060224_rpssummary.htm) plus prorated volume of annual growth to meet target in 2010. This goal differs from the individual utilities' renewables forecasts, which are based on more complex modeling assumptions. Renewable electric generation, as defined for the purpose of the 20% goal, excludes generation from large hydroelectric plants.

(3) Increase reflects only impacts of equipment installed after 12/31/2005.

(4) Electricity and natural gas savings goals per CPUC Decision, D.04-09-060, September 23, 2004. Tables 1A, 1B and 1C.

(5) Total gas savings are **annual** savings from equipment installed after 12/31/2005.

SUPPLY OUTLOOK/PIPELINE CAPACITY

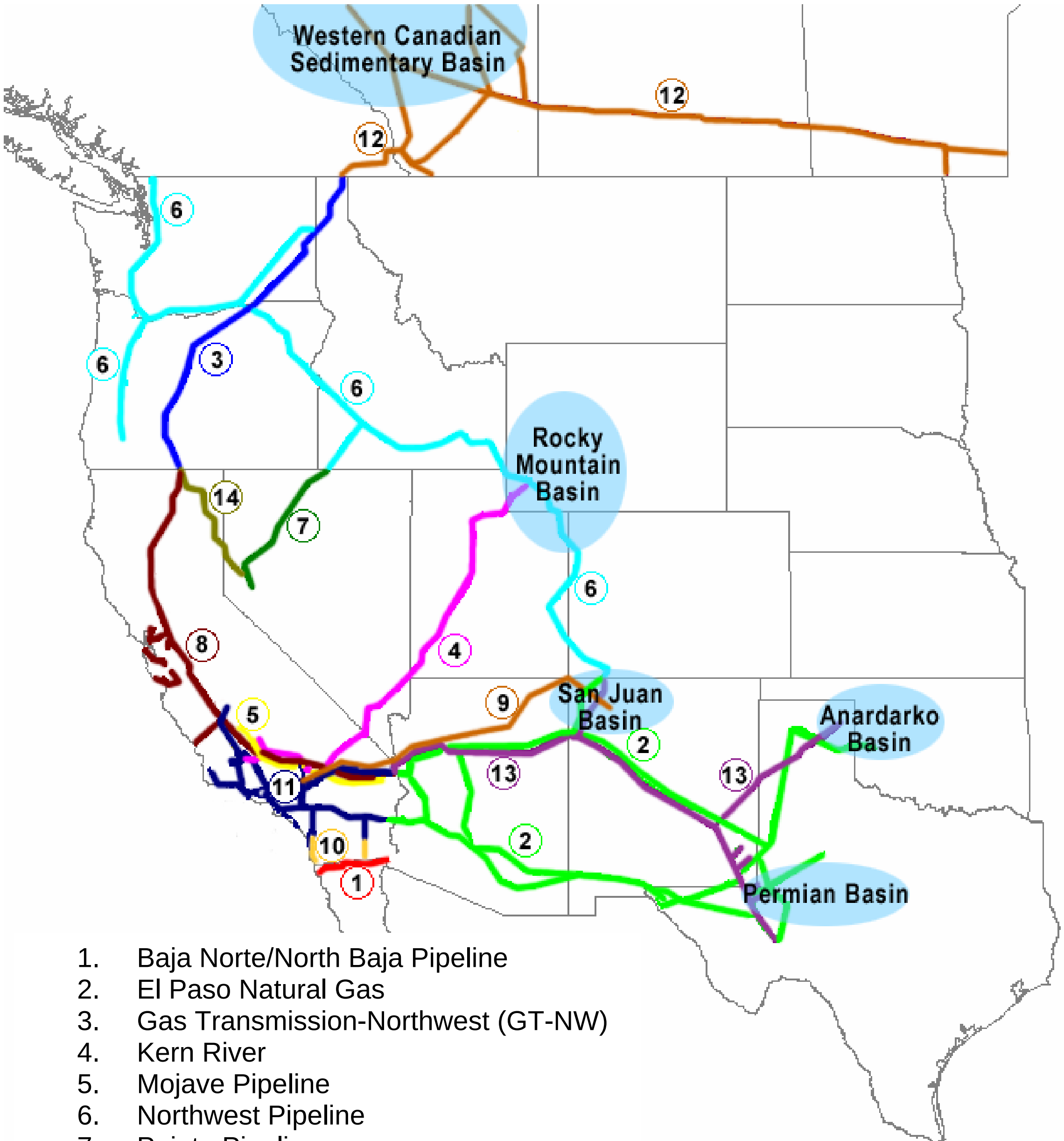
California's existing gas supply portfolio is regionally diverse and includes supplies from California sources (onshore and offshore), Southwestern U.S. supply sources (the Permian, Anadarko, and San Juan Basins), the Rocky Mountains, and Canada. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

Additional pipeline capacity and open access have contributed to long-term supply availability and gas-on-gas competition. Interstate pipelines currently serving California include El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission-Northwest, Transwestern Pipeline Company, Questar Southern Trails Pipeline, and Tuscarora Pipeline.

NATURAL GAS PROJECTS: PROPOSALS, COMPLETIONS, AND LIQUEFIED NATURAL GAS

Over the past three years, California natural gas utilities, interstate pipelines, and instate natural gas storage facilities have increased their delivery and receipt capacity to meet natural gas demand growth. In addition, more projects have been proposed and some are under construction. The California Energy Commission (Energy Commission) posts a list of natural gas projects on their website, which track both completed projects and ones that are being developed or in the proposal stage, along with proposed liquefied natural gas (LNG) projects. To review these project lists check the Energy Commission's website at http://www.energy.ca.gov/naturalgas/

Western North American Natural Gas Pipelines



1. Baja Norte/North Baja Pipeline
2. El Paso Natural Gas
3. Gas Transmission-Northwest (GT-NW)
4. Kern River
5. Mojave Pipeline
6. Northwest Pipeline
7. Paiute Pipeline
8. PG&E Company
9. Questar Southern Trail
10. SDG&E Company
11. SoCalGas Company
12. TransCanada Pipeline
13. Transwestern Pipeline
14. Tuscarora Gas Transmission

STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of gas supplies and gas requirements (demand).

Gas sales and transportation volumes are consolidated under the general category of system gas requirements. Details of gas transportation for individual utilities are given in the tabular data for northern California and Southern California. The wholesale category includes the City of Long Beach Gas and Oil Department, San Diego Gas & Electric Company, Southwest Gas Corporation, Los Angeles Department of Water and Power, Alpine Natural Gas, Island Energy, West Coast Gas, Inc, and the municipalities of Coalinga and Palo Alto. Gas service to the power plants for the City of Vernon is scheduled to commence during the forecast period.

Some columns may not sum precisely, because of modeling accuracy and rounding differences, and do not imply curtailments.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
MMcf/Day

	2006	2007	2010	2015	2020	2025
California's Supply Sources						
Utility						
California Sources	442	442	441	441	442	441
Out-of-State	4,308	4,379	4,346	4,335	4,582	4,911
Net Withdrawal (Injection)	0	0	0	0	0	0
Utility Total	4,749	4,820	4,787	4,776	5,024	5,352
Non-Utility Served Load (1)	1,550	1,504	1,527	1,448	1,455	1,477
Statewide Supply Sources Total	**6,299**	**6,324**	**6,314**	**6,224**	**6,479**	**6,829**
California's Requirements						
Utility						
Residential	1,254	1,272	1,313	1,355	1,376	1,408
Commercial	505	510	519	510	492	490
Natural Gas Vehicles	26	26	33	39	46	54
Industrial	822	818	819	796	775	764
Electric Generation (2)	1,474	1,541	1,457	1,424	1,663	1,925
Enhanced Oil Recovery-Steaming	35	35	20	20	20	20
Wholesale/International+Exchange	420	403	413	418	431	464
Company Use and Unaccounted-for	89	90	89	89	94	101
Utility Total	4,624	4,695	4,662	4,651	4,898	5,227
Non-Utility						
EOR Steaming	695	677	653	625	598	575
EOR Cogen	212	212	212	211	220	231
Industry	49	45	40	27	31	32
Electric Generation	594	571	622	585	607	637
Non-Utility Served Load (1)	1,550	1,504	1,527	1,448	1,455	1,477
Statewide Requirements Total (3)	**6,173**	**6,199**	**6,189**	**6,099**	**6,353**	**6,703**

Notes:

(1) Consists of deliveries by Kern/Mojave pipelines to industrial, EOR cogen, EOR steaming and powerplant customers, and gas uses at Blythe, Elk Hills and Otay Mesa powerplants. Source: CEC 2005 IEPR.

(2) Includes utility generation and cogeneration.

(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
MMcf/Day

Utility	2006	2007	2010	2015	2020	2025
Northern California						
California Sources (1)	130	130	130	130	130	130
Out-of-State	1,973	2,036	2,114	2,136	2,339	2,508
Net Withdrawal/(Injection)	0	0	0	0	0	0
Northern California Total	2,103	2,166	2,244	2,266	2,469	2,638
Southern California						
California Sources (2)	312	312	311	311	312	311
Out-of-State	2,335	2,343	2,232	2,199	2,243	2,403
Net Withdrawal/(Injection)	0	0	0	0	0	0
Southern California Total	2,647	2,655	2,543	2,510	2,554	2,714
Utility Total	4,749	4,820	4,787	4,776	5,024	5,352
Non-Utility Served Load (3)	1,550	1,504	1,527	1,448	1,455	1,477
Statewide Supply Sources Total	**6,299**	**6,324**	**6,314**	**6,224**	**6,479**	**6,829**

Notes:

(1) Includes utility purchases and exchange/transport gas.

(2) Includes utility purchases and exchange/transport gas and City of Long Beach "on source" gas.

(3) Consists of deliveries by Kern/Mojave pipelines to industrial, EOR cogen, EOR steaming and powerplant customers, and gas uses at Blythe, Elk Hills and Otay Mesa powerplants. Source: CEC 2005 IEPR.

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
MMcf/Day

	2006	**2007**	**2010**	**2015**	**2020**	**2025**
Utility						
Northern California						
Residential	554	574	602	621	632	643
Commercial - Core	230	237	247	253	256	259
Natural Gas Vehicles - Core	5	4	8	11	15	20
Natural Gas Vehicles - Noncore	1	1	1	1	1	1
Industrial - Noncore	410	412	416	406	404	402
Wholesale	10	10	10	10	10	10
SMUD Electric Generation	95	108	125	188	247	308
Electric Generation (2)	634	654	660	600	724	811
Exchange (CA and Southwest Gas)	1	1	10	10	10	10
Company Use and Unaccounted-for	39	40	41	42	46	50
Northern California Total	1,979	2,042	2,120	2,142	2,345	2,514
Southern California						
Residential	700	698	711	734	744	765
Commercial - Core	218	216	213	198	176	170
Commercial - Noncore	57	57	58	60	60	61
Natural Gas Vehicles - Core	20	21	24	27	30	33
Industrial - Core	64	62	59	52	43	39
Industrial - Noncore	349	344	343	337	328	323
Wholesale	409	392	393	398	411	444
Electric Generation (3)	745	779	671	636	692	806
Enhanced Oil Recovery - Steaming	35	35	20	20	20	20
Company Use and Unaccounted-for	50	50	48	47	48	51
Southern California Total	2,645	2,653	2,542	2,509	2,553	2,713
Utility Total	4,624	4,695	4,662	4,651	4,898	5,227
Non-Utility Served Load (4)	1,550	1,504	1,527	1,448	1,455	1,477
Statewide Gas Requirements Total (5)	**6,173**	**6,199**	**6,189**	**6,099**	**6,353**	**6,703**

Notes:
(1) Includes transportation gas.
(2) Northern Calfornia Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
(3) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(4) Consists of deliveries by Kern/Mojave pipelines to industrial, EOR cogen, EOR steaming and powerplant customers, and gas uses at Blythe, Elk Hills and Otay Mesa powerplants. Source: CEC 2005 IEPR.
(5) Does not include off-system deliveries.

STATEWIDE SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary is intended to complement the existing five-year recorded data tables included in the tabular data sections for each utility.

The information displayed in the following tables shows, by customer class, the composition of supplies from both out-of-state and California sources and is based on the utilities' accounting records and on available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to reconciling adjustments. In addition, some of the data are based on allocations and assignments that, by necessity, rely on estimated information. These tables have been updated to reflect the most current information.

Some columns may not sum exactly, because of factored allocation and rounding differences, and do not imply curtailments.

Recorded 2001 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	38	556	274	58	30	10	31	998
Noncore Commercial/Industrial	70	157	75	40	54	11	(9)	399
EG (3)	221	495	236	125	171	36	(27)	1,257
EOR	5	11	5	3	4	1	(1)	29
Wholesale/Resale/International (4)	80	275	103	51	31	14	(78)	475
Total	415	1,495	694	276	290	72	(83)	3,158
Pacific Gas and Electric Company (5)								
Core	29	110	94	574	6	-	-	813
Noncore Commercial/Industrial/EG/Resale	157	563	81	864	78	-	-	1,743
Total	186	673	175	1,438	84	-	-	2,556
Other Northern California								
Core (6)	-	-	-	-	-	-	10	10
Non-Utilities Served Load (7)								
Direct Sales/Bypass	400	-	-	-	334	173	-	907
TOTAL SUPPLIER	1,001	2,168	869	1,714	708	245	(73)	6,631

Notes:

(1) Includes storage activities.
(2) Includes NGV volumes.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company (8)								
Core	9	45	17	43	4	4	16	136
Noncore Commercial/Industrial	1	205	77	3	0	0	1	288
Total	9	250	94	46	4	4	17	424

(5) Under PG&E's Gas Accord structure implemented in 1998, it became possible to make purchases at a Citygate point. Since the source of Citygate purchases cannot be readily determined, any Core, UEG or Wholesale Citygate purchases have been distributed between the other sources
(6) Includes Southwest Gas Corp., Avista and Tuscarora data.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) SDG&E data revised from previous reports.

Recorded 2002 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	73	588	251	49	29	6	(13)	984
Noncore Commercial/Industrial	78	83	75	54	107	13	24	433
EG (3)	161	166	151	108	214	27	42	869
EOR	6	7	7	5	10	1	3	39
Wholesale/Resale/International (4)	79	266	65	47	31	13	(76)	425
Total	398	1,109	550	264	390	60	(20)	2,750
Pacific Gas and Electric Company (5)								
Core	53	92	90	578	4	-	-	817
Noncore Commercial/Industrial/EG/Resale (3)	134	456	12	840	32	-	-	1,474
Total	187	548	102	1,418	36	-	-	2,291
Other Northern California								
Core (5)	-	-	-	-	-	-	11	11
Non-Utilities Served Load								
Direct Sales/Bypass	380	-	-	-	365	183	-	928
TOTAL SUPPLIER	965	1,657	652	1,682	791	243	(9)	5,981

Notes:
(1) Includes storage activities.
(2) Includes NGV volumes.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company (8)								
Core	3	47	11	41	1	-	24	127
Noncore Commercial/Industrial	0	194	47	2	0	-	1	244
Total	3	241	59	43	1	-	24	371

(5) Includes Southwest Gas Corp., Avista and Tuscarora data.
(6) SDG&E data revised from previous reports.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2003 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	57	575	245	23	26	5	6	938
Noncore Commercial/Industrial	63	68	64	53	139	14	11	411
EG (3)	121	130	122	101	267	27	21	789
EOR	7	7	6	5	14	1	1	42
Wholesale/Resale/International (4)	58	197	66	55	37	13	(49)	377
Total	306	976	503	238	483	61	(11)	2,557
Pacific Gas and Electric Company (5)								
Core	-	146	9	569	9	-	-	733
Noncore Commercial/Industrial/EG/Resale (3)	155	305	78	595	157	-	64	1,354
Total	155	451	87	1,164	166	-	64	2,087
Other Northern California								
Core (5)	-	-	-	-	-	-	11	11
Non-Utilities Served Load (6)								
Direct Sales/Bypass	451	-	-	-	600	86	-	1,137
TOTAL SUPPLIER	912	1,427	590	1,402	1,249	147	64	5,791

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	3	43	14	49	12	0	13	135
Noncore Commercial/Industrial	0	136	45	1	0	0	0	183
Total	3	179	60	50	12	0	13	317

(5) Includes Southwest Gas Corp., Avista and Tuscarora data.

(6) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2004 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	71	599	226	45	43	-	8	994
Noncore Commercial/Industrial	56	63	54	91	142	10	0	416
EG (3)	105	118	101	171	266	19	1	781
EOR	5	5	5	8	12	1	0	35
Wholesale/Resale/International (4)	57	158	134	52	48	10	(33)	427
Total	294	943	520	367	511	40	(23)	2,653
Pacific Gas and Electric Company (5)								
Core	-	158	65	578	18	-	-	819
Noncore Industrial/Wholesale/EG (3)	104	294	22	609	252	-	-	1,281
Total	104	452	87	1,187	270	-	-	2,100
Other Northern California								
Core (6)	-	-	-	-	-	-	11	11
Non-Utilities Served Load								
Direct Sales/Bypass	475	-	-	-	757	91	-	1,323
TOTAL SUPPLIER	873	1,395	607	1,554	1,538	131	(12)	6,087

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	5	29	25	47	-	-	44	150
Noncore Commercial/Industrial	0	114	97	1	-	-	1	213
Total	5	144	122	47	-	-	45	363

(5) Kern River supplies include volumes on Kramer Junction Interconnect and Questar Southern Trails Interconnect.

(6) Includes Southwest Gas Corporation, Avista, and Tuscarora data

(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2005 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	60	600	208	18	106	-	(16)	976
Noncore Commercial/Industrial	56	43	59	52	172	7	16	404
EG (3)	94	71	99	87	287	11	26	676
EOR	5	4	5	4	14	1	1	34
Wholesale/Resale/International (4)	55	161	107	52	48	7	(35)	393
Total	270	878	478	213	627	25	(8)	2,483
Pacific Gas and Electric Company (5)								
Core	-	193	52	535	11	-	-	791
Noncore Industrial/Wholesale/EG (3)	117	306	55	592	151	-	-	1,221
Total	117	499	107	1,127	162	-	-	2,012
Other Northern California								
Core (6)	-	-	-	-	-	-	11	11
Non-Utilities Served Load (7)								
Direct Sales/Bypass	474	-	-	-	675	108	-	1,257
TOTAL SUPPLIER	861	1,377	585	1,340	1,464	133	3	5,763

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(2) Includes NGV volumes, unaccouted-for and company use.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	42	28	46	1	-	26	149
Noncore Commercial/Industrial	0	104	69	1	-	-	-	174
Total	6	146	97	47	1	-	26	323

(5) Kern River supplies include volumes on Kramer Junction Interconnect and Questar Southern Trails Interconnect.

(6) Includes Southwest Gas Corporation, Avista, and Tuscarora data

(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

2006 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 3.9 million residential customers and 219,000 businesses in northern and central California. In addition to serving residential, commercial, and industrial markets, PG&E provides gas transportation and storage services to a variety of gas-fired electric generation plants in its service area. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from south of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, customers also utilize the PG&E system to meet their gas needs in southern California.

The forecast in this report covers the years 2006 through 2025. However, as a matter of convenience, the tabular data at the end of the section show only the years 2006 through 2012 and the years 2015, 2020, and 2025.

The northern California section of the report begins with the demand forecast, including a discussion of economic conditions, forecast methodology, and other factors affecting demand in various markets. Following the gas demand forecast are discussions of gas supply and pipeline capacity. Abnormal peak day demands and supply resources, as well as gas balances, are discussed at the end of this section.

GAS DEMAND

OVERVIEW

PG&E's 2006 California Gas Report (CGR) average year demand forecast projects total on-system demand growing at an annual average rate of 1.3 percent between 2006 and 2025. This overall growth rate is a combination of 0.9 percent annual growth in the core market and 1.7 percent annual growth in the noncore market. By comparison, the 2004 CGR estimated an annual average growth rate of 1.3 percent per year, based on growth of 0.9 percent per year for the core market and 1.6 percent per year for the noncore market, very close to the current report's projected growth rates. [1]

The projected rate of growth of the core market has not changed. The forecast rate of growth of the noncore market has increased very slightly due to less dramatic declines in projected load for the industrial sector.

In the 2006 CGR, total gas demand by electric generators and cogenerators in Northern California is estimated to increase at a rate of about 2.3% per year from 2007 through 2025. This total gas demand includes gas demand by SMUD's gas-fired power plants. It excludes gas delivered by third-party pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in central California.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed from econometric models. Forecasts for other sectors (NGV, wholesale) are developed from market information. Forecasts of gas demand by power plants are based on modeling of the electricity market in the Western Electricity Coordinating Council using the MarketBuilder model. While variation in short-term gas use depends mainly on prevailing weather conditions, longer-term trends in gas demand are driven primarily by underlying economic, demographic, and technological changes, such as growth in population and employment; changes in prevailing prices; growth in electricity demand and in electric generation by renewables; and changes in the efficiency profiles of residential and commercial buildings and the appliances within them.

[1] The period used for calculating the 2004 CGR growth rates is 2004-2025.

MARKET SENSITIVITY

The average-year gas demand forecast presented here is a reasonable projection for an uncertain future. However, point forecasts cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, appliance saturation, and efficiencies). In order to give some flavor of the possible variation in gas demand, PG&E has developed an alternative forecast of gas demand under assumed high demand conditions.

For the high-demand condition scenario, PG&E relied on a weather vintage approach. PG&E forecast total gas demand for, say, 2007, assuming the demographic conditions and infrastructure likely to exist in 2007, but with the 2007 weather conditions set to match the worst conditions actually recorded during the past 35 years. Previous analyses had shown that weather conditions from November 1976 through October 1977 were the worst. That period was extremely dry in both northern California and the Pacific Northwest. In addition, the winter of 1976-1977 was somewhat colder than normal.[2]

Temperature

Because space heating accounts for a high percentage of use, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's average-year forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 20 years.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the average-year scenario and gas use will vary accordingly. PG&E's high demand forecast assumes that winter temperatures in the forecast horizon will be the same of those which prevailed during November 1976-October 1977.

Seasonal variations in temperature have relatively little effect on power plant gas demand and, consequently, PG&E's forecasts of power plant gas demand in the 2006 CGR are based on average temperatures. (Each summer typically contains a few heat waves with temperatures 10 or 15 degrees Fahrenheit above normal, which lead to peak electricity demands and drive up power plant gas demand; however, on a seasonal basis, temperatures seldom deviate more than 2 degrees Fahrenheit from average.)

[2] As an alternative to the weather vintage method, PG&E considered a different approach, specifically, using the coldest winter in forecasting residential and commercial demand, and the worst drought in forecasting power plant gas demand. This approach has the disadvantage of an unknown probability of occurrence.

Hydro Conditions

In contrast to temperature deviations, annual runoff for hydroelectric plants has varied by 50% above and below the long-term annual average. The impact of dry conditions was demonstrated during the drought and electricity crisis in water year 2001 (October 2000 through September 2001). For the 2006 CGR's high demand scenario, as noted above, PG&E used the 1977 drought, which was more severe in both northern California and the Pacific Northwest than the 2001 drought.

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 1.3 percent annually from 2006 to 2025. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies. This decline accelerated sharply in 2001 when gas prices spiked, causing temperature-adjusted residential gas demand to plunge by more than 8 percent. After recovering somewhat in 2002 and 2003, temperature-adjusted gas use per household reverted to its long-term trend and fell by 1.7 percent and 2.7 percent in 2004 and 2005, respectively. Due to continuing upgrades in appliance and building efficiencies, PG&E forecasts residential demand to grow on average at 0.9 percent per year from 2006 to 2025, implying an average decrease in gas use per household of nearly 0.4 percent per year.

Commercial

The number of commercial customers in the PG&E service area is projected to grow on average by a little less than 1 percent per year from 2006 to 2025. The 2000-2001 noncore to core migration wave has caused this class to be less temperature sensitive than it had previously been and has also tended to stunt overall growth in both customer base and gas use per customer. Gas use per commercial customer is projected to remain flat over the forecast horizon. Over the next 20 years, sales for this sector are expected to grow by the rate at which the customer base is forecast to increase.

Industrial

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector plummeted by close to 20 percent in 2001 due to a combination of soaring gas prices, noncore to core migration and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 and has remained fairly flat since that point in time due to high real natural gas prices and to continuing structural problems in California's manufacturing sector. Industrial gas consumption is expected to slowly decline by about 0.1 percent annually over the next 20 years as California's manufacturing sector continues to gradually shrink.

Electric Generation

PG&E forecasts gas demand for most cogenerators by assuming a continuation of past usage, with modifications for expected expansions or closures. Operations at most cogenerators are not strongly affected by prices in the wholesale electricity market because electricity is co-produced with some other product, usually steam, for an industrial process.

PG&E forecasts gas demand by power plants and market-sensitive cogenerators using the MarketBuilder model. MarketBuilder is an economic-equilibrium model that has been applied to various markets with geographically distributed supplies and demands, such as the North American natural gas market. PG&E uses MarketBuilder to simulate the electricity market in the Western Electricity Coordinating Council, which encompasses the electric systems from Denver to the Pacific Coast, and from northern Mexico to British Columbia and Alberta.

PG&E's forecast for 2007-2025 uses the base-case electricity demand forecast from the CEC's 2005 Integrated Energy Policy Report. For areas outside California, PG&E used many assumptions from the reference case prepared by the Planning Working Group of the Seams Steering Group—Western Interconnection. The Planning Working Group consists of personnel from various state agencies and electric transmission organizations in the WECC.

SMUD EG

The Sacramento Municipal Utility District is the sixth largest community owned municipal utility in the United States and it provides electric service to over 550,000 customers within the greater Sacramento area. SMUD operates three cogeneration plants and a peaking turbine with a total capacity of approximately 500 MW. The peak gas load of those units is approximately 100,000 Dth/d and the average load is typically about 60,000 Dth/d. In addition, in February 2006 SMUD began commercial operation at Cosumnes, which is a 500 MW gas-fired combined-cycle plant with a peak gas load of approximately 85,000 Dth/d.

SMUD owns and operates a pipeline connecting Cosumnes and the three cogeneration plants to PG&E's backbone system near Winters, Ca. SMUD owns an equity interest of approximately 3.6 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401, representing about 88,000 Dth of capacity.

GAS SUPPLY SOURCES

CALIFORNIA-SOURCE GAS

Northern California-source gas supplies come primarily from gas fields in the Sacramento Valley. In 2005, PG&E's customers obtained on average 117 MMcf/d of California source-gas.

U. S. SOUTHWEST GAS

PG&E's customers have access to three major U.S. Southwest gas producing basins--Permian, San Juan, and Anadarko--via the El Paso, Southern Trails, and Transwestern pipeline systems.

PG&E's customers can purchase gas in the basins and transport it to California via interstate pipelines. Customers can also purchase gas supplies at the California-Arizona border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

CANADIAN GAS

PG&E's customers can purchase Canadian gas from various suppliers in western Canada (British Columbia and Alberta) and transport it to California primarily through Gas Transmission Northwest Pipeline. Customers can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

ROCKY MOUNTAIN GAS

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Pipeline and via the Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon.

STORAGE

In addition to storage services offered by PG&E, Wild Goose Storage, Inc. and Lodi Gas Storage, LLC provide storage services from the Wild Goose and Lodi facilities, respectively.

NEW GAS SUPPLIES

PG&E anticipates that sufficient new supplies will be available from a variety of sources at market-competitive prices to meet existing and projected market demands in its service area. The new supplies could be delivered through a variety of sources, including new interstate pipeline facilities and expansion of PG&E's existing transmission facilities, or PG&E's or others' storage facilities.

In the near term (2008-2015), the most likely new source of supply will be liquefied natural gas (LNG) imports. Such imports will provide a new supply source whether directly connected to the PG&E system, or delivered across other systems to PG&E. The mere presence of large LNG supplies in the West, Southwest, and Gulf Coast areas will increase supply and at a minimum make other supplies more available if the LNG takes market share away elsewhere. Supplies of LNG can be expected to have a favorable impact on price in that they, in the worst case, can be expected to dampen price increases, and in the best case, produce lower prices than currently exist.

The project nearest to California furthest along in development is Sempra LNG's Costa Azul project, on the Mexico's Baja Peninsula. Deliveries from the project are expected to begin in 2008, and will likely move both directly into southern California, as well as on to interstate pipelines that can access northern California. The facility will also serve markets in Mexico. While the project is currently sized at 1.0 Bcf/d, Sempra has announced plans to expand the project significantly.

Other projects along both the Mexican coast and the US west coast are in various stages of preliminary development but have not received final permits to begin construction. It is quite feasible that one or more of these other projects will move to completion and begin deliveries, but this is not likely to occur before 2010, at the earliest.

On a longer term horizon, 2015 and beyond, the most likely other possibility of new supply appears currently to be gas from near the Arctic Circle delivered through an Alaska pipeline, or via a pipeline through Canada's McKenzie Delta in the Northwest Territory, or both. These pipelines could be capable of transporting several Bcf/d each to Canadian and US markets, including those in California. Neither pipeline has received final approvals and completion is likely to be about 10 years away.

INTERSTATE PIPELINE CAPACITY

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990's. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

Almost all of PG&E's noncore customers buy all or most of their gas supply needs directly from the market. They use PG&E's transportation and storage services to meet their gas supply needs.

INTERSTATE GAS PIPELINE CAPACITY

As a result of pipeline expansion and new projects, California utilities and end-users benefit from improved access to supply basins and enhanced gas-on-gas and pipeline-to-pipeline competition. Interstate pipelines serving northern and central California include the El Paso, Mojave, Transwestern, Gas Transmission Northwest, Southern Trails, and Kern River pipelines. These pipelines provide northern and central California with access to gas producing regions in the U. S. Southwest and Rocky Mountain areas, and in western Canada.

U.S. Southwest and Rocky Mountains

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Southern Trails, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 1,140 MMcf/day.

Canada

PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission Northwest at Malin, Oregon. The Redwood Path has a firm capacity of 2,021 MMcf/day.

ABNORMAL PEAK DAY SUPPLY AND DEMAND

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of core demand under extremely adverse conditions. The design criteria for PG&E, as required under CPUC regulation, is a 29 degree Fahrenheit system-weighted mean temperature. This corresponds to a roughly 1 in 90 extreme temperature event. The APD core load demand forecast is estimated to be approximately 3.1 Bcf/d. The APD load forecast shown here excludes all noncore demand and, in particular, excludes all EG demand. PG&E estimates that total noncore demand during an APD event would be 1.5 Bcf/d, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD forecast is developed using statistical tools to estimate the relationship of daily core gas usage to daily weather conditions during several recent winters. This relationship is then used to simulate what the core load would be under the adverse weather conditions that occurred on December 21, 1990, the coldest day on record in PG&E's service area.

FORECAST OF APD SUPPLY AVAILABILITY

For APD planning purposes, supplies will flow under core's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's underground storage facilities located at McDonald Island, Los Medanos, and Pleasant Creek. Flowing supplies may come from Canada, the U.S. Southwest, the Rocky Mountain Region, SoCalGas, and California. Supplies could also be purchased from noncore customers once gas enters the PG&E system. PG&E's Core Gas Supply Department is responsible for managing the flowing supplies to PG&E's core customers in the event of an APD occurrence. Core aggregators serving core transport customers on PG&E's system have the obligation to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme cold weather events PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as the cold weather front drops down from Canada with a two to three day lag before hitting PG&E's service territory. There is also impact on supply from the southwest. While prices can influence the availability of supply to our system, cold weather can affect producing wells in the basins which, in turn, can affect the total supply to our system and others.

Under APD conditions, PG&E can, if necessary, divert gas from the noncore (including gas fired electric generators) to meet core demand. Diversion of noncore supply in lieu of expanding firm core supplies has been the basis for infrastructure system planning for years, based on the assumption that the noncore market would either shut down its use of gas or switch to an alternate fuel. However, little, if any, alternate fuel burn capability exists today, so supply diversions from the noncore would necessitate that noncore customers (including EG) shut down operations. The implication for the future is that under APD conditions a significant portion of EG customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that in the near term, noncore demand (including gas fired electric generation) on an APD would be 1.5 Bcf/day. With the additions of the Wild Goose and Lodi storage facilities, more noncore demand will be satisfied in the event of an APD. However, looking to the future, if gas fired electric generation grows as forecasted, supplemental supplies will eventually be needed if the goal is to serve the core load and most, if not all, noncore load. These supplemental supplies could be in the form of additional storage facilities or incremental pipeline capacity.

Pacific Gas and Electric Company
Forecast of Core Gas Demand and Supply on an Abnormal Peak Day (APD)
MMcf/Day

	2006-07	2007-08	2008-09	2009-10	2010-11
ADP Core Demand	3,053	3,122	3,178	3,213	3,242
Firm Storage Withdrawal	1,006	1,006	1,006	1,006	1,006
Required Flowing Supply	2,047	2,116	2,172	2,207	2,236
Total APD Resources (to meet demands)	3,053	3,122	3,178	3,213	3,242

Notes:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD planning criterion: system temperature on APD is 29º F.

(2) Includes supplies flowing under firm and as-available capacity, and capacity made available pursuant to supply diversion arrangements.

2006 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2001-2005
MMCF/DAY

LINE		2001	2002	2003	2004	2005	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
1	Core Purchases	29	53	0	0	0	1
2	Customer Gas Transport & Exchange	157	134	155	104	117	2
3	Total California Source Gas	186	187	155	104	117	3
	OUT-OF-STATE GAS						
	Core Net Purchases						
6	Rocky Mountain Gas	6	4	9	18	11	6
7	U.S. Southwest Gas	204	182	155	223	245	7
8	Canadian Gas	574	578	569	578	535	8
	Customer Gas Transport						
10	Rocky Mountain Gas	78	32	170	252	151	10
11	U.S. Southwest Gas	644	468	434	316	361	11
12	Canadian Gas	864	840	595	609	592	12
13	Total Out-of-State Gas	2,370	2,104	1,932	1,996	1,895	13
14	STORAGE WITHDRAWAL(2)	142	303	327	260	250	14
15	Total Gas Supply Taken	2,698	2,594	2,414	2,360	2,262	15
	GAS SENDOUT						
	CORE						
19	Residential	543	557	546	536	512	19
20	Commercial	244	249	244	235	233	20
21	NGV	2	2	5	3	4	21
22	Total Throughput-Core	789	808	795	774	749	22
	NONCORE						
24	Industrial	420	406	418	428	431	24
25	Electric Generation (1)	1100	830	739	808	753	25
26	EOR	1	0	0	0	0	26
27	NGV	1	1	1	1	1	27
28	Total Throughput-Noncore	1522	1237	1158	1237	1185	28
29	WHOLESALE	11	9	10	10	10	29
30	Total Throughput	2322	2054	1963	2021	1944	30
31	CALIFORNIA EXCHANGE GAS	1	1	1	1	2	31
32	STORAGE GAS(2)	252	316	341	285	268	32
33	SHRINKAGE Company Use / Unaccounted for	123	223	109	53	48	33
34	Total Gas Send Out (3)	2,698	2,594	2,414	2,360	2,262	34
	CURTAILMENT / ALTERNATIVE FUEL BURNS(4)						
37	Residential, Commercial, Industrial	0	0	0	0	0	37
38	Utility Electric Generation	0	0	0	0	0	38
39	TOTAL CURTAILMENT	0	0	0	0	0	39

NOTES:

(1) Electric generation includes gas deliveries by PG&E to cogeneration, PG&E-owned electric generation, other non-utility generation, and SMUD generation.
(2) Includes both PG&E and third party storage
(3) Total gas send-out excludes off-system transportation.
(4) UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2006-2010
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2006	2007	2008	2009	2010	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path[1]	1,140	1,140	1,140	1,140	1,140	2
3	Redwood Path[2]	2,021	2,021	2,021	2,021	2,021	3
4	**Supplemental[3]**	0	0	0	0	0	4
5	**Total Supplies Available**	3,291	3,291	3,291	3,291	3,291	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	1,973	2,036	2,030	2,069	2,114	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,103	2,166	2,160	2,199	2,244	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,103	2,166	2,160	2,199	2,244	11
REQUIREMENTS FORECAST BY END USE							
	CORE						
12	Residential	554	574	586	596	602	12
13	Commercial	230	237	242	245	247	13
14	NGV	5	4	6	7	8	14
15	**Total Core**	789	815	834	848	857	15
	NONCORE						
16	Industrial	410	412	414	417	416	16
17	SMUD Electric Generation[4]	95	108	112	116	125	17
18	PG&E Electric Generation[5]	634	654	617	633	660	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas[6]	0	0	7	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,151	1,186	1,162	1,187	1,222	23
24	**Off-System Deliveries[7]**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	39	40	40	41	41	25
26	**TOTAL END USE**	2,103	2,166	2,160	2,199	2,244	26
27	System Curtailment	0	0	0	0	0	27

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Forecast by PG&E, not by SMUD.

(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system. Forecast for 2006 reflects current hydro conditions.

(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve Southwest demand demand after this point.

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2010-2025
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2011	2012	2015	2020	2025	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path[(1)]	1,140	1,140	1,140	1,140	1,140	2
3	Redwood Path[(2)]	2,021	2,021	2,021	2,021	2,021	3
4	**Supplemental[(3)]**	0	0	0	0	0	4
5	**Total Supplies Available**	3,291	3,291	3,291	3,291	3,291	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2,161	2,168	2,136	2,339	2,508	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,291	2,298	2,266	2,469	2,638	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,291	2,298	2,266	2,469	2,638	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential	607	609	621	632	643	12
13	Commercial	249	250	253	256	259	13
14	NGV	8	9	11	15	20	14
15	**Total Core**	864	868	885	903	922	15
	Noncore						
16	Industrial	414	411	406	404	402	16
17	SMUD Electric Generation[(4)]	139	144	188	247	308	17
18	PG&E Electric Generation[(5)]	686	688	600	724	811	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas[(6)]	9	9	9	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,260	1,264	1,215	1,396	1,542	23
24	**Off-System Deliveries[(7)]**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	42	42	42	46	50	25
26	**TOTAL END USE**	2,291	2,298	2,266	2,469	2,638	26
27	System Curtailment	0	0	0	0	0	27

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Forecast by PG&E, not by SMUD.

(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.

(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve Southwest demand demand after this point.

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2006-2010
MMCF/DAY
HIGH DEMAND YEAR

LINE		2006	2007	2008	2009	2010	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path[1]	1,140	1,140	1,140	1,140	1,140	2
3	Redwood Path[2]	2,021	2,021	2,021	2,021	2,021	3
4	**Supplemental[3]**	0	0	0	0	0	4
5	**Total Supplies Available**	3,291	3,291	3,291	3,291	3,291	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	1,986	2,304	2,295	2,330	2,379	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,116	2,434	2,425	2,460	2,509	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,116	2,434	2,425	2,460	2,509	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential	563	584	597	609	616	12
13	Commercial	233	241	245	249	251	13
14	NGV	5	4	6	7	8	14
15	**Total Core**	801	829	848	865	875	15
	Noncore						
16	Industrial	410	412	414	417	416	16
17	SMUD Electric Generation[4]	95	123	131	137	146	17
18	PG&E Electric Generation[5]	634	890	843	851	880	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas[6]	0	0	7	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,151	1,436	1,408	1,426	1,464	23
24	**Off-System Deliveries[7]**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	40	45	45	45	46	25
26	**TOTAL END USE**	2,116	2,434	2,425	2,460	2,509	26
27	System Curtailment	0	0	0	0	0	27

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by PG&E, not by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system. Forecast for 2006 reflects current hydro conditions.
(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve Southwest demand demand after this point.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2011-2025
MMCF/DAY
HIGH DEMAND YEAR

LINE		2011	2012	2015	2020	2025	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path[1]	1,140	1,140	1,140	1,140	1,140	2
3	Redwood Path[2]	2,021	2,021	2,021	2,021	2,021	3
4	**Supplemental[3]**	0	0	0	0	0	4
5	**Total Supplies Available**	3,291	3,291	3,291	3,291	3,291	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2,444	2,454	2,430	2,650	2,832	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,574	2,584	2,560	2,780	2,962	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,574	2,584	2,560	2,780	2,962	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential	622	627	645	670	692	12
13	Commercial	253	253	257	257	260	13
14	NGV	8	9	11	15	20	14
15	**Total Core**	883	889	913	942	972	15
	Noncore						
16	Industrial	414	411	406	404	402	16
17	SMUD Electric Generation[4]	166	173	230	283	342	17
18	PG&E Electric Generation[5]	918	918	818	954	1,045	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas[6]	9	9	9	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,519	1,523	1,475	1,662	1,810	23
24	**Off-System Deliveries[7]**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	48	48	48	52	56	25
26	**TOTAL END USE**	2,574	2,584	2,560	2,780	2,962	26
27	System Curtailment	0	0	0	0	0	27

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Forecast by PG&E, not by SMUD.

(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.

(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve Southwest demand demand after this point.

(7) Deliveries to southern California.

2006 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

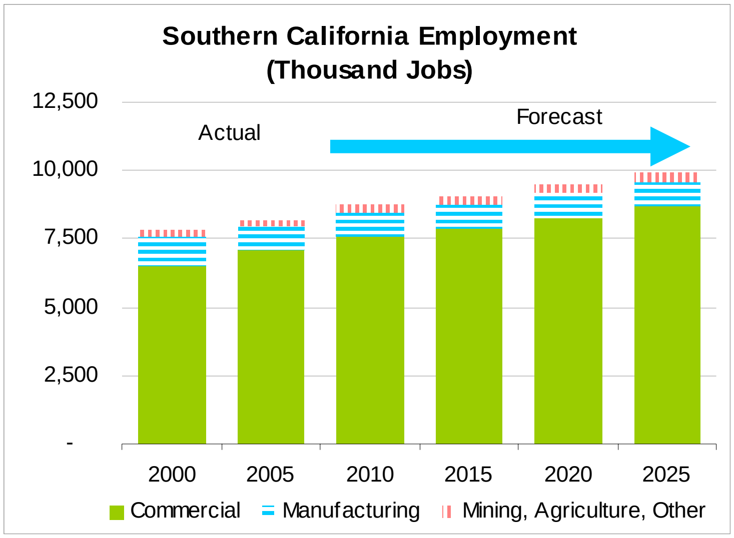
Southern California Gas Company (SoCalGas) is the principal distributor of natural gas in Southern California, providing retail and wholesale customers with transportation, exchange and storage services and also procurement services to most retail core customers. SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery (EOR) and electric generation (EG) customers in Southern California. San Diego Gas & Electric Company (SDG&E), Southwest Gas Corporation, and the City of Long Beach Energy Department are SoCalGas' three wholesale utility customers. Wholesale gas service for power plants in the City of Vernon is expected during the forecast period.

This report covers a 20-year natural gas demand forecast period, from 2006 through 2025; only the consecutive years 2006 through 2012 and the point years 2015, 2020 and 2025 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

The Southern California section of the *2006 California Gas Report* (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The natural gas price forecast methodology used to develop the gas demand forecast is discussed followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

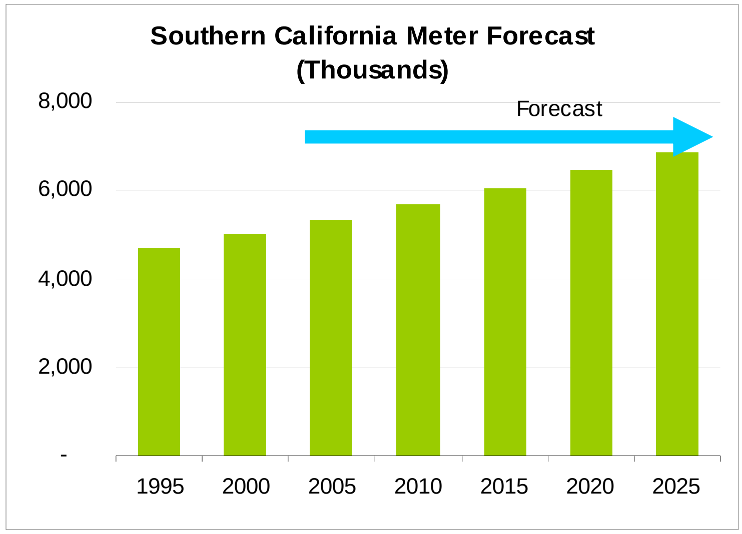
THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS



The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. After enjoying strong growth in the late 1990's, the SoCalGas service area's 12-county economy slowed from 2001 through 2003. The area's total employment then rebounded somewhat, growing 1.4% in 2004 and another 1.8% in 2005. Local industrial employment (manufacturing and mining) remains weak, dropping 1.6% in 2005—and is expected to grow only 0.2% in 2006. After many years of declines, the area's industrial jobs now stand 30% beow their 1989 peak of 1.3 million. Non-industrial employment is faring better. In 2005, local commercial jobs (all jobs except industrial) saw 2.2% growth. In 2006, forecasters expect local commercial employment to grow by 1.8%, with business and professional services and construction continuing to have the fastest rates of job growth based on economic forecasts developed by Global Insight.

From 2005 through 2010, total service-area jobs are expected to grow an average of 1.3% per year. In the longer term, service-area employment growth is expected to slow as the area population's average age gradually increases--part of a national demographic trend of aging "baby boomers". As the population ages and as more people retire, we expect employment to grow at slower rates. From 2010 through 2025, total local job growth should average approximately 0.9% per year. Service-area industrial jobs are forecasted to grow very slowly, averaging only about 0.1% per year from 2005 through 2025. We expect the industrial share of total employment to fall from 10.9% in 2005 to 9.2% by 2025. Commercial job growth is expected to average a little above 1.0% annually from 2005 through 2025.



SoCalGas' service-area population grew about 1.5% in 2005—slowing from 2.0% growth as recently as 2003. The service area population is forecasted to grow modestly by an average of 1.2% per year from 2006 through 2025. At least two factors are dampening local population growth. First, the high cost and low affordability of housing is driving more residents out of state to look for cheaper housing, and is also discouraging people from moving to California from other parts of the country. Second, foreign immigration into Southern California --traditionally the factor that has kept the region's population growth rate much higher than the US average – has begun to taper off slightly; recently, more new immigrants are spreading out and settling to work in other parts of the USA. Mainly as a result of modest growth in population and new households, SoCalGas expects its active meters to increase an average of just under1.3% per year from 2005 to 2025.

REGULATORY ENVIRONMENT

The past year witnessed numerous proceedings at both the California Public Utilities Commission (CPUC) and Federal Energy Regulatory Commission (FERC) designed to make the natural gas industry more responsive to the changing needs of the marketplace.

State Regulatory Matters

The Gas Market OIR (R.04-01-025) was issued in January 2004 to establish policies and rules to ensure reliable, long-term supplies of natural gas to California. This OIR was initiated to respond to recent industry reports, Federal Energy Regulatory Commission (FERC) orders, and ongoing changes in the natural gas market, which indicated that in the long-term, there may not be sufficient natural gas supplies and/or infrastructure to meet the requirements of all California residential and business consumers. This OIR focuses on the time period from 2006 to 2016 and seeks to address a broad range of supply issues, to increase gas demand reduction efforts, ensure sufficient interstate pipeline capacity is available to serve California, maximize the utilization and benefits of storage facilities, and enable access of imported liquefied natural gas (LNG) supplies to utility pipeline systems. Each of the California natural gas public utilities are respondents to R.04-01-025, which was bifurcated into two phases; Phase 1 to address proposals regarding the acquisition of interstate pipeline capacity, and Phase 2 to address infrastructure adequacy.

A decision in Phase 1 of R.04-01-025 was issued in September 2004. In D.04-09-022, the Commission approved with modifications, SoCalGas' methodology and framework to be used by the CPUC for granting pre-approval of new interstate transportation agreements, which will enable SoCalGas' Gas Acquisition Department to efficiently diversify its interstate pipeline capacity portfolios, while enhancing supply reliability and gas price stability. In addition, D.04-09-022 established that new gas supplies should have equal access to utility systems in order to compete on equal footing with existing supplies.

In particular, D.04-09-022 was driven by the fact that SoCalGas' existing pipeline capacity contracts were expiring. The contracts with Transwestern Pipeline Company (Transwestern) expired in November 2005 and the primary contracts with El Paso Natural Gas Company (El Paso) expire in August 2006. SoCalGas subsequently acquired capacity on the Kern River Gas Transmission Company (Kern River) system, and four capacity contracts with El Paso. These contracts expire between 2007 and 2011. In 2005, SoCalGas obtained two new capacity contracts with Transwestern that expire in 2009 and 2011. All interstate transportation capacity under the pre-approved contracts will be used to transport natural gas supplies on behalf of the California utilities' core residential and small commercial customers, and all costs of the capacity will be recovered in the customers' procurement rates.

Phase II of R.04-01-025 was continued to deal with infrastructure adequacy and policies for expansion of backbone, natural gas quality, local transmission, and unbundled storage. These issues were fully litigated in 2005 and a decision by the Commission is expected in 2006.

D.04-09-022 also ordered SoCalGas to file a separate application to address its proposal for firm access rights to the SoCalGas system. In A.04-12-004, SoCalGas again put forth its proposal for a system of firm access rights to the SoCalGas system and also to integrate the two gas transmission systems of SoCalGas and San Diego Gas & Electric Company (SDG&E) on an economic basis. The Commission subsequently bifurcated A.04-12-004 into two phases; Phase 1 would address system integration issues with regard to the SoCalGas and SDG&E systems and Phase 2 would address the firm access rights and issues related to off-system delivery to Pacific Gas & Electric Company's (PG&E) transmission system.

SoCalGas' system integration proposal sought to combine the transmission-related costs of SoCalGas and SDG&E so that customers of each utility share in the transmission costs of both utilities. These integrated transmission rates would allow customers of SoCalGas and SDG&E to obtain gas at the same transportation rate from any existing or new receipt point on the

SoCalGas and SDG&E systems. In April 2006, the Commission issued D.06-04-033 approving the SoCalGas/SDG&E system integration proposals.

The second phase of A.04-12-004 was initiated following the Commission's issuance of D.06-04-033 to address firm access rights and off system deliveries to PG&E. A Commission decision in Phase 2 is expected by the end of 2006.

Federal Regulatory Matters

SoCalGas participates in FERC proceedings relative to interstate capacity serving California. One of the most important current proceedings is the El Paso General Rate Case (RP05-422), which was filed in June 2005. Key issues in this case include the development of hourly and daily balancing services for El Paso's customers whose load profiles vary throughout the gas day. The loads of electric generators and distribution utilities are highly weather sensitive and the lack of market area storage facilities connected to the El Paso system require the pipeline to balance these shippers' loads in order to maintain system integrity. In the interest of promoting cost responsibility, so that shippers pay for the services they use, and ensuring the reliability and certainty of supply deliveries to California from the El Paso pipeline system, SoCalGas supports these new services. An initial decision is expected August 2007.

SoCalGas also holds contracts for interstate transportation capacity on the Kern River Pipeline and on Transwestern Pipeline. Kern River filed its rate case in November 2004. In this highly contentious case, rate design, particularly Kern's levelized cost methodology, and return on equity, are two of the most controversial issues being litigated in the case. An Order on the Initial Decision is expected mid-June 2006. Transwestern plans to file its rate case in November 2006.

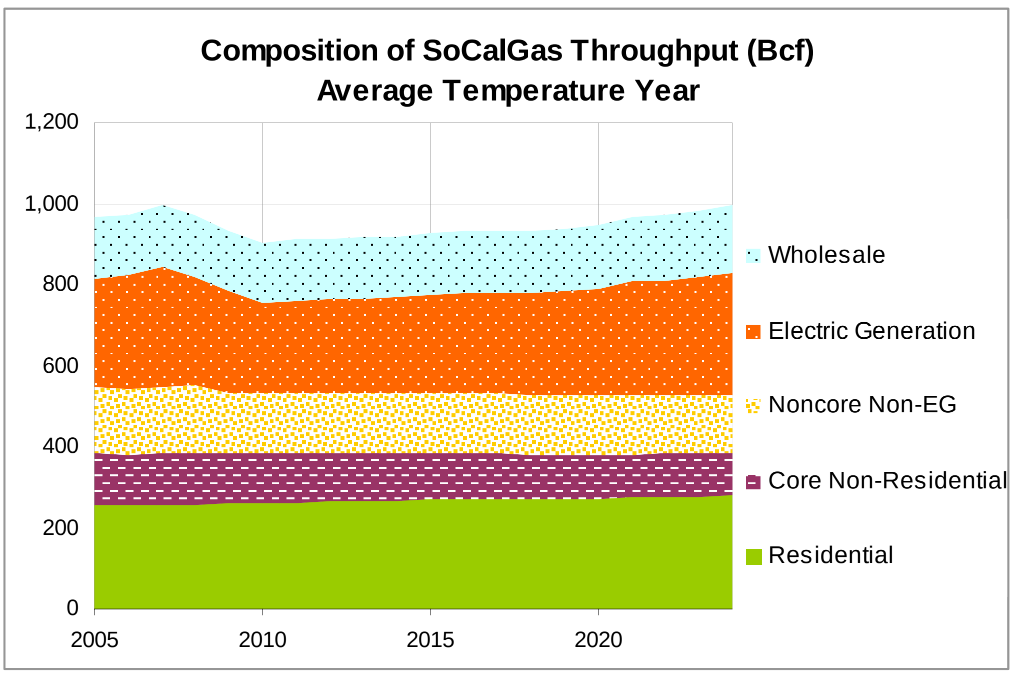
Another proceeding of note is the North Baja Pipeline (NBP) expansion. On February 7, 2006, TransCanada filed an application for a two-phase expansion of its North Baja Pipeline and for construction of a lateral to serve the Imperial Irrigation District's El Centro generating station. The project proposes to import up to 2.7 Bcf/day of re-gasified Liquefied Natural Gas (LNG) supply from terminals in Baja California, Mexico. The project will link to a corresponding expansion of the Gasoducto Bajanorte line in Mexico. North Baja is proposing to construct a 36-inch interconnect with SoCalGas' existing 36-inch pipeline at NBP's proposed Blythe Meter Station site. The anticipated in-service date for Phase I of the project is October 2007 and for Phase II the anticipated date is June 2010. SoCalGas is participating in this proceeding.

GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects gas demand for all its market sectors to grow at an annual average rate of 0.15% from 2006 to 2025. The continued growth in the residential, wholesale, as well as in the electric generation sectors pushes demand higher. However, the decline in commercial and industrial demand, and continued increased use of non-utility pipeline systems by EOR customers, moderates the overall increase in utility-served demand. By comparison, the *2004 California Gas Report* projected almost no growth. The difference between the two forecasts is caused by the see-saw effects of several factors, but the two most significant influences are the changes in the CPUC-mandated energy efficiency (EE) savings goals and associated programs and electric demand increases in the medium- to long-term.

The following chart shows the composition of SoCalGas' throughput for the recorded year 2005 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and for the 2006 to 2025 forecast period.



Notes:

1. Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, natural gas vehicles, company-use, and lost and unaccounted-for.
2. Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming
3. Electric generation includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
4. Wholesale includes sales to the City of Long Beach, Vernon EG, SDG&E and Mexicali.

Residential and wholesale gas requirements are expected to grow a cumulative 9% between 2006 and 2025 as the population in the service area continues to grow. The core commercial and industrial markets are expected to show some modest customer gains due to the growing economy; however, very aggressive energy efficiency goals and associated programs are projected to drastically reduce this load 19% by 2025. Non-core commercial/industrial markets are expected to decline less slowly due to more moderate energy efficiency programs in this sector. Utility gas demand for EOR steaming operations, which have declined since the Kern/Mojave pipeline began offering direct service to California customers in 1992, are expected to continue to decline as more utility service contracts expire. The non-core non-cogeneration load as a whole is expected to decline to 144 Bcf by 2025 from 160 Bcf in 2006. Lastly, gas demand in the electric generation (EG) market is expected to drop sharply in 2010 due to the expected departure of a large cogeneration customer. After 2010, the gas-fired EG load is expected to grow as large EG power plants increase operations to meet growing electricity demand. Electric generation load is expected to grow from 270 Bcf in 2006 to 298 Bcf in 2025, a cumulative increase of 10%.

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for two design temperature conditions – average and cold – to quantify changes in space heating demand due to weather. Temperature variations can cause significant changes in winter gas demand due to space heating in the residential and core commercial and industrial markets. The largest demand variations due to temperature occur in the month of December. Heating Degree Day (HDD) differences between the two conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. One HDD is when the average temperature for the day drops 1 degree below 65° Fahrenheit. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a recurrence period of 35 years.

MARKET SECTORS

Residential

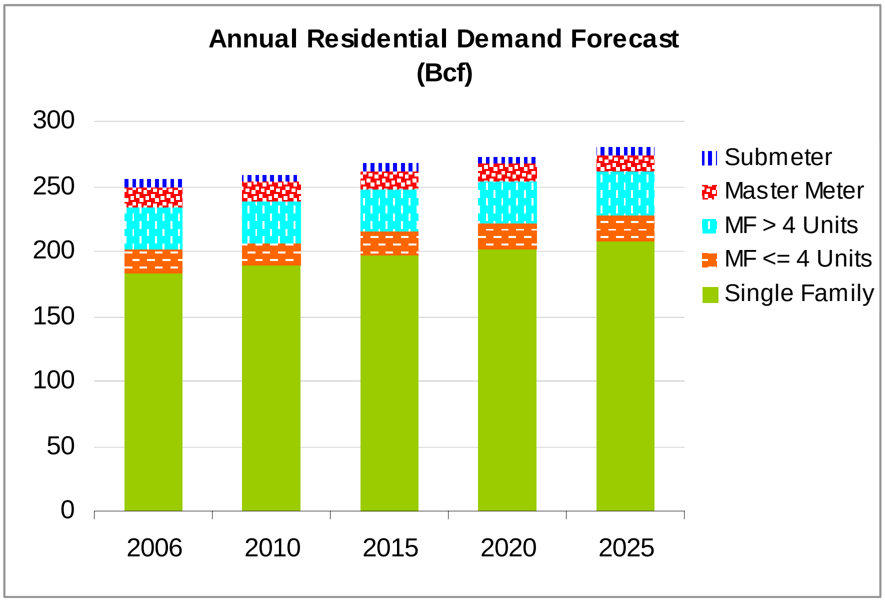
Residential demand adjusted for temperature totaled 252 Bcf in 2005. The unadjusted residential demand for 2005 was 5.6% less than the temperature adjusted total for Southern California because of warmer than normal weather conditions exhibited throughout the year. The actual, observed cumulative Heating Degree Days for 2005 were approximately 13% less than the totals that characterize the average year weather design for SoCalGas.

The total residential customer count for SoCalGas consists of five residential segment types. These are single family, small and large multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 5.12 million in 2005. This amount reflects a 61,365 meter increase relative to the 2004 total. The overall observed 2004-2005 residential meter growth was 1.2%.

For the forecast period covering 2006 through 2025, residential meters are estimated to increase at an average annual rate of 1.3%. Forecasted population growth in SoCalGas' service territory is expected to drive an increase in connected residential single family and multi-family customers. In contrast, master meter and sub-metered customers, which constitute only a small portion of the overall residential customer count, have been declining in recent years because existing master meters and sub-meters are being converted to individually-metered customers. Over the forecast period, the master meter and sub-metered customer counts are expected to decline by an average of 0.8% per year. By the year 2025, the total residential meter count is expected to reach 6.64 million.

Use per meter for all classes of residential customers is forecasted to decline due to the expected energy savings from tightened building and appliance standards and utility energy efficiency programs. In 2005, the single family and multi-family average annual use per meter were 532 therms and 330 therms, respectively. By 2025, the single and multi-family average use per meter is forecasted to decline to 505 and 300 therms, respectively. At the end of the forecast period, the average use per residential customer is expected to fall to 430 therms per year. The change reflects a 14.5% decline in the temperature adjusted annual usage per customer due to continued improvements in the efficiency of appliances, tighter building shells and the cumulative impact of energy efficiency programs administered by the utilities.

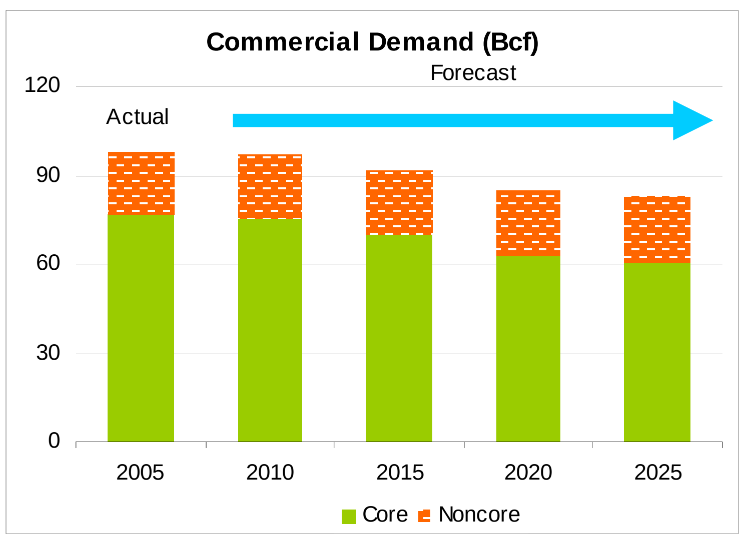
The projected residential natural gas demand will be influenced primarily by residential meter growth and the forecasted declining use per customer. These combined trends yield a projected growth in residential demand of only 0.5% per year. In 2005, residential demand was 254 Bcf. By the year 2025, residential demand is expected to reach 279 Bcf. The difference reflects an average increase of 1.3 Bcf per year. The graph below illustrates the projection.



Commercial

On a temperature-adjusted basis, core commercial market demand in 2005 totaled 79 Bcf, up about 0.6 Bcf, or 0.8%, from 2004. On average, core commercial market demand is forecast to decrease about 1.1% per year, over the next 20 years, to just below 63 Bcf in 2025. The decrease in gas demand is mainly the result of gas demand decreases expected from the impact of CPUC-authorized energy efficiency programs in this market.

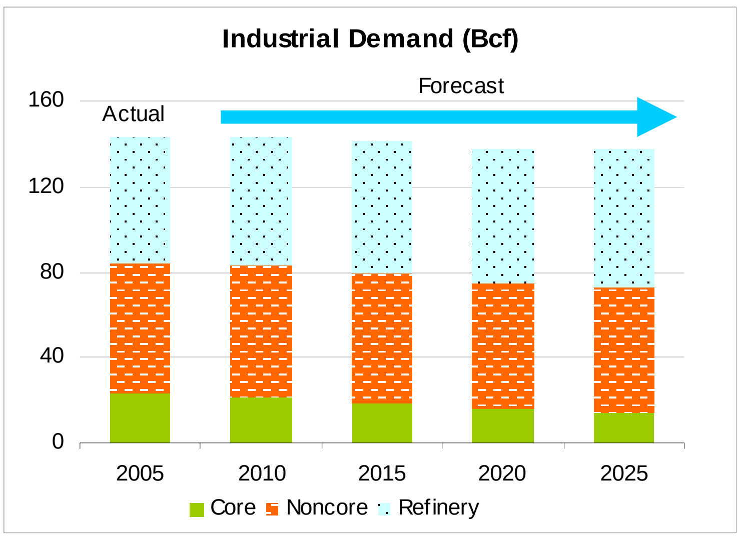
After five years of continuing load decreases, mostly due to the migration of non-core customers to core customer status, non-core commercial demand is expected to show some modest growth due to the cessation of non-core customers' migration to core service. Non-core commercial demand is expected to be 21 Bcf in 2006; a slight increase of about 0.2 Bcf from the previous year. The non-core commercial market is expected to grow at an annual rate of 0.4% primarily due to the increase in commercial economic activity in the agriculture, health, transportation, communication and



utilities (TCU) industrial sectors. CPUC-authorized energy efficiency programs will moderate the demand growth in this market sector which is expected to reach 22 Bcf by 2025.

Industrial

In 2005, temperature-adjusted core industrial demand was 23 Bcf which is 0.6 Bcf (2%) lower than 2004 deliveries. Core industrial market demand is projected to decrease by 2% per year from 23 Bcf in 2006 to 14 Bcf in 2025. This decrease in gas demand results from a combination of a slightly higher forecasted growth in industrial production that is countered by minor increases in marginal gas rates and the impact of CPUC-authorized energy efficiency programs savings in this market.

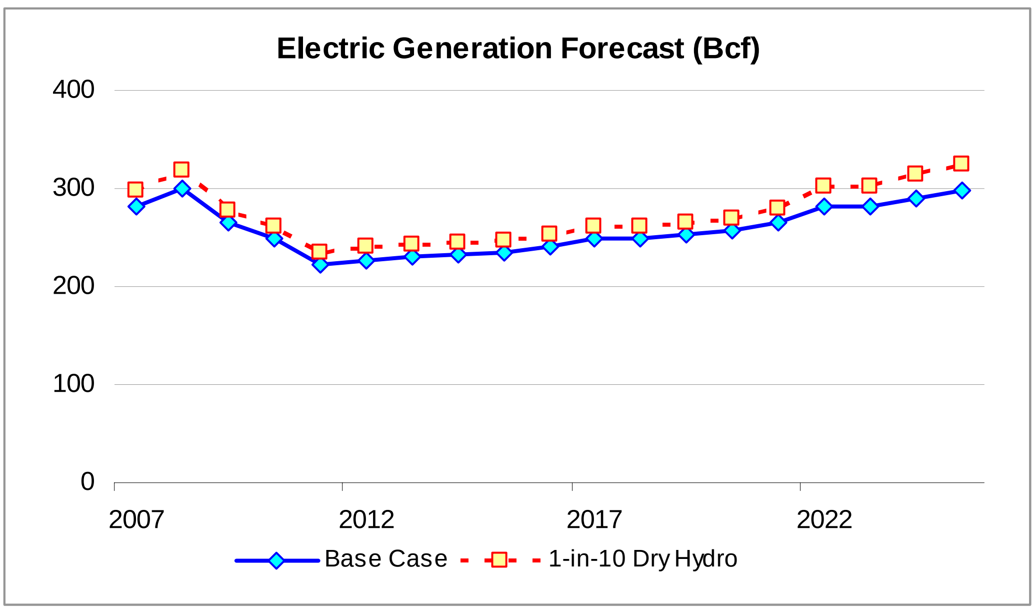


Retail non-core industrial gas demand has been stable despite high gas price increases and migration of customers from non-core to core service in the last few years. However, gas demand growth for individual business sectors within this market varies widely. The food sector experienced the fastest growth at 4% annually since 2003, whereas the transportation sector posted a total drop of 13% during the same period. Gas demand for the retail non-core industrial market as a whole is expected to decline gradually at a rate of 0.25% annually, from 61 Bcf in 2005 to 58 Bcf by 2025. The reduced demand is primarily due to the expected slowdown of economic activity in the mining and petroleum sectors, the gradual decline in energy intensity among all sectors and Commission-authorized energy efficiency programs designed to reduce gas demand. The EE programs-induced demand reductions are expected to reduce non-core industrial load by 1.5 Bcf by 2025.

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery industrial gas demand is forecast to decline 0.3% per year, from 63 Bcf in 2005 to 59 Bcf in 2025. This decrease is mainly due to refiners' using alternate fuels such as petroleum coke and butane during summer months when their cost of natural gas is forecasted to be less competitive than the cost of these alternate fuels. The reduction of refinery gas demand also reflects the savings from CPUC-authorized energy efficiency programs.

Electric Generation

This sector includes the following markets: all commercial/industrial cogeneration; EOR-related cogeneration; and, non-cogeneration electric generation. It should be noted that the forecasts of EG-related load are subject to a higher degree of uncertainty due to the following: the continued operation of existing generation facilities; the timing and location of new generation facilities in the western United States; the regulatory and market decisions that impact the operation of existing cogeneration facilities; the timing and construction of new renewable resources; and, the construction of additional electric transmission lines. The forecast is based on a power market simulation for the period 2006 to 2025 and thus reflects the anticipated dispatch of all of the EG resources in the SoCalGas service territory under base electricity demand and average and low hydroelectric availability market conditions. The following graph shows total EG forecasts for normal year and 1-in-10 dry hydro year.



Industrial/Commercial/Cogeneration <20MW

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. In 2005, recorded gas deliveries to this market were 17 Bcf, 0.7 Bcf lower than 2004 deliveries and 0.5 Bcf higher than 2003 deliveries. Projected demand in this market segment is separated into existing load and added load from expected participation in the CPUC-authorized Self-Generation Incentive Program (SGIP). The existing load is expected to grow at a modest rate tied to the gradual growth of business activity, whereas the added load is expected to grow at a faster rate due to the SGIP incentive program. This forecast assumes funding for the SGIP would be extended to 2017. Overall commercial/industrial cogeneration demand is projected to grow at 0.9% per year to about 21 Bcf by 2025.

Industrial/Commercial Cogeneration >20 MW

For commercial/industrial cogeneration customers greater than 20 MW, gas demand is forecast to decline 51%, from 56 Bcf in 2006 to 28 Bcf in 2011. This sharp reduction is caused by the expected fuel switching of a large customer in 2011. For the remaining period, the forecast remains relatively flat. This ‘regulatory status quo’ forecast assumes that the investor-owned utilities continue to have an obligation to buy all power from these facilities. These rules may change in the future which could therefore have a significant impact on the forecast.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration is forecast to remain stable at the year 2005 level of 18 Bcf.

Enhanced Oil Recovery-Related Cogeneration

In 2005, recorded gas deliveries to the EOR-related cogeneration market were 14.8 Bcf, the same as in 2004. EOR-related cogeneration demand is expected to decrease slightly to 14.6 Bcf in 2006 and remain at that level until 2008 when usage will start to drop due to the expiration of several of SoCalGas' long-term EOR gas transportation contracts. Demand is forecast to level off in 2010 at 3.7 Bcf and remain at that level for the remainder of the forecast period.

Non-Cogeneration Electric Generation

For the non-cogeneration EG market, gas demand is forecast to decline 8%, from 166 Bcf in 2006 to 153 Bcf in 2011. This reduction is the result of new electric transmission lines, CPUC renewable goals, and some customer taking service from non-utility pipelines. For the remaining period, the forecast increases 2.5% per year, from 153 Bcf in 2011 to 224 Bcf in 2025.

SoCalGas' forecast includes the construction of approximately 50,000 MW of new thermal electric power generating resources in the western United States over the entire 20-year forecast period. Of that total, 7,000 MW of new thermal generating resources are under construction and are expected to be online by the end of 2008. Throughout the entire planning period, SoCalGas assumes that market participants will construct additional generation resources such that the Western Electricity Coordinating Council maintains a minimum planning reserve margin of 15%. For electricity demand within California, SoCalGas used the reference case from the California Energy Commission's (CEC) *2005 Integrated Energy Policy Report (IEPR)*; however, SoCalGas did not incorporate uncommitted electric Demand Side Management programs. Since natural gas is generally the marginal fuel for power generation, EG demand could be significantly higher or lower should actual electricity demand be higher or lower than this CEC forecast. For electric end-use demand outside of California, SoCalGas used Global Energy's electric demand forecast.

Starting in 2006, an approximation of known renewable generation was ramped up to meet the CPUC target that 20% of the electric energy distributed in 2010 by the Investor-Owned electric Utilities (IOU) be supplied by renewable sources. The renewable-sourced energy generation in 2010 was estimated by taking 20% of the IOU's forecasted load from the CEC's 2005 IEPR electricity demand forecast. Starting in 2017, the renewable energy requirement was calculated by taking 20% of the IOU's and the other California Load Serving Entities' forecasted load. If for any reason the utilities fail to meet the 20% renewable goals, then the gas demand would increase, since natural gas is generally the marginal fuel used for power generation.

SoCalGas performed a dry hydro sensitivity gas demand forecast. Due to the displacement of generation by off-system resources, the impact of significant hydro conditions had little impact on SoCalGas' EG gas demand. A 1-in-10 dry hydro year, as defined by the CEC, increased gas demand, on average, for the forecast period by 15 Bcf per year.

Enhanced Oil Recovery – Steam

Recorded deliveries to the EOR steaming market in 2005 were 12.5 Bcf, a slight decrease of 0.2 Bcf from 2004. SoCalGas' EOR steaming demand is expected to remain stable at 12.4 Bcf from 2006 until 2008 when SoCalGas' long-term EOR gas transportation contracts terminate in late 2008. From 2009 through the end of the forecast period, gas demand is expected to be approximately 7.0 Bcf. These figures include gas delivered to PG&E's EOR customers through inter-utility exchange. In 2005, 0.01 Bcf of gas was delivered to PG&E through such arrangements. No change in demand is expected in that market. The EOR-related cogeneration demand is discussed in the Electric Generation sector.

Crude oil prices are not expected to reach a level that would initiate any major expansion in California EOR operations during the forecast period. As a result, EOR production is expected to gradually decline by approximately 1.5 % percent per year over the forecast period. In addition, oil producers will rely increasingly on interstate pipelines serving California to supplant traditional supply sources, such as own source gas and SoCalGas' transportation system.

Wholesale and International

The forecast of wholesale gas demand includes transportation to SDG&E, the City of Long Beach Electric and Gas Department (Long Beach), Southwest Gas Corporation (SWG), and the City of Vernon (Vernon).

Under average year temperature conditions, total non-electric generation gas requirements for SDG&E are expected to increase at an average growth rate of 0.5% per year from 55 Bcf in 2006 to 60 Bcf in 2025.

The forecast of the large EG loads in SDG&E's service area is based on the power market simulation as noted in the Electric Generation chapter for "non-cogeneration EG" demand. SoCalGas forecasts an increase in cogeneration and non-cogeneration for SDG&E's EG gas requirements of 0.6% per year, from 64 Bcf in 2006 to 72 Bcf in 2025.

The cogeneration EG demand growth for SDG&E is based on the CEC's projected self-generation load for the San Diego service area in the *2005 Integrated Energy Resource Plan*. The same assumptions used for the retail non-cogeneration EG demand were used for the wholesale non-cogeneration EG demand.

SoCalGas/SDG&E performed a 1-in-10 year dry hydro sensitivity forecast. Due to the displacement of generation by off-system resources, the impact of significant hydro conditions had little impact on SDG&E's EG gas demand. A dry hydro year, as defined by the CEC, increased SDG&E's EG demand on average for the forecast period by 3 Bcf per year.

For the City of Long Beach, SoCalGas used the forecast prepared by Long Beach for this report. Long Beach's gas use is expected to stay steady at 12 Bcf/ year. Long Beach's local deliveries are expected to stay steady at around 0.5 Bcf/year. SoCalGas' transportation to Long Beach is expected to stay steady at around 11.5 Bcf/year.

The demand forecast for Southwest Gas is based on a long-term demand forecast prepared by Southwest Gas. In 2006, SoCalGas will serve approximately 7.5 Bcf directly, with another 3.6 Bcf being served by PG&E under exchange arrangements with SoCalGas. The direct service load is expected to grow by 2% per year from 7.5 Bcf in 2006 to approximately 11.1 Bcf in 2025.

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June, 2005. The forecasted throughput starts at 3 Bcf in 2006 and declines to 2 Bcf by 2025. The throughput forecast for the EG customers is based on a power market simulation.

SoCalGas used the forecast prepared by Ecogas, Mexicali, for this report. Mexicali's use is expected to increase from 4.6 Bcf at an average rate of 0.7% per year to 5.3 Bcf in 2025.

Natural Gas Vehicles (NGV)

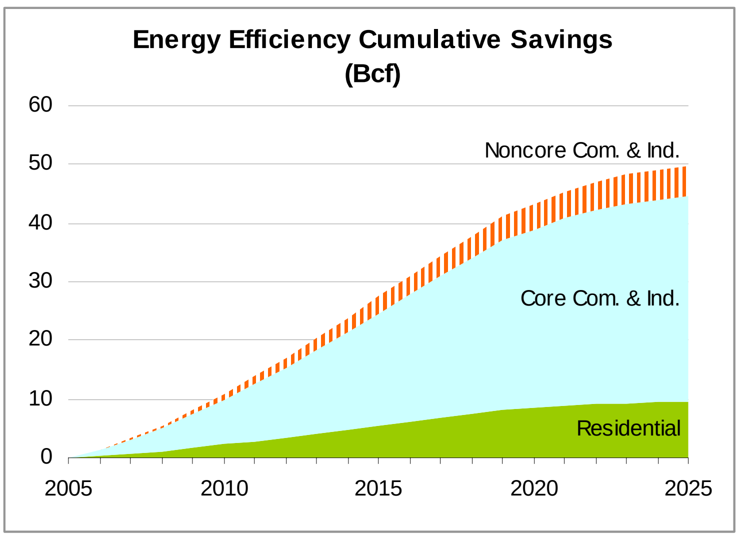
At the end of 2005, there were 213 compressed natural gas (CNG) fueling stations serving approximately 20,000 vehicles that consumed 7.1 Bcf of natural gas during the year. SoCalGas remains optimistic about the NGV market's growth, forecasting an increase in demand from 7.1 Bcf in 2005 to 10.1 Bcf in 2015 and 12.5 Bcf in 2025. The growth is being propelled by the private and public sectors, with customer support from SoCalGas' Low Emission Vehicles (LEV) program.

SoCalGas recently introduced a new tariff for home NGV refueling. Currently, there is one type of known home refueling appliance unit on the market in the SoCalGas service territory. This unit is manufactured by FuelMaker; it allows customers to refuel their NGVs at home using their existing residential gas service meter. We expect that this product will enhance the growth of the NGV market by providing support to the growing NGV station infrastructure.

ENERGY EFFICIENCY PROGRAMS

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage while still maintaining a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the Energy Efficiency programs.

The cumulative net Energy Efficiency load impact forecast for selected years is shown in the graph below. The net load impact includes all Energy Efficiency programs that SoCalGas and SDG&E have forecasted to be implemented in the years 2006 through 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.



Savings reported are for measures installed under SoCalGas' Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' Energy Efficiency programs, and only for the measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2005 with a lifetime of 10 years is only included in the forecast through 2014. Naturally occurring conservation that is not attributable to SoCalGas' Energy Efficiency activities is not included in the Energy Efficiency forecast.

Details of SoCalGas' 2006-2008 Energy Efficiency program portfolio are contained in SoCalGas' Advice Letter 3588 which was submitted on February 1, 2006 and became effective March 3, 2006.

Notes:
1. Energy Efficiency load impacts include 2003-2004 program savings, but do not include pre-2003 program savings.
2. "Hard" impacts include measures requiring a physical equipment modification or replacement.
3. SoCalGas does not include "soft" impacts, e.g., energy management services type measures.
4. The assumed average measure life is 15 years.

CAPACITY, SOURCES, AND STORAGE

INTERSTATE PIPELINE CAPACITY

Southern California continues to operate in an environment of interstate pipeline capacity in excess of anticipated demand. Interstate pipeline delivery capability into Southern California is over 4,000 MMcf/day, with approximately 3,230 MMcf/day available directly to SoCalGas' customers (the remaining interstate capacity serves non-local distribution company customers). These pipeline systems provide access to several large supply basins, located in: New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains and Western Canada. The interstate pipeline systems, along with local California gas supplies, deliver gas to most Southern California customers through SoCalGas' system.

SoCalGas currently has firm receipt capacity at the following locations for its customers to access supply from interstate pipelines.

Current Interstate and Local Firm Capacity
MMcf/d

	Capacity
El Paso at Blythe	1,210
El Paso at Topock	540
North Needles (Transwestern, Questar Southern Trails)	800
Hector Road (Mojave)	50
Wheeler Ridge (PG&E, Kern/Mojave, CA Production)	765
Line 85 (CA Production	190
North Coastal (CA Production)	120
Kramer Junction (Kern/Mojave)	200
Total Firm Supply Access	**3,875**

GAS SUPPLY SOURCES

Southern California receives gas supplies from several sedimentary basins in the western United States and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountain, Western Canada, and local California supplies.

California Gas

Gas supply available to SoCalGas from California sources (state onshore plus state/federal offshore supplies) was 274 MMcf/day in 2005.

Southwestern U.S. Gas

Traditional Southwestern U.S. sources of natural gas, especially from the San Juan Basin, will continue to supply most of Southern California's natural gas demand. This gas is delivered via the El Paso Natural Gas Company and Transwestern Pipeline Company pipelines. The San Juan Basin's conventionally produced gas supplies have increased since 1991 and are expected to meet Southern California's gas demand. Permian Basin's gas also provides an additional source of supply into California.

Rocky Mountain Gas

Rocky Mountain supply presents a viable alternative to traditional Southwestern U.S. gas sources for Southern California. This gas is delivered to Southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. In recent years, Rocky Mountain gas has increasingly flowed to Midwestern and Pacific Northwest markets.

Canadian Gas

SoCalGas anticipates that the role of Canadian gas in meeting Southern California's demand during the forecast period will decline. New pipeline capacity out of western Canada to the U.S. Midwest and eastern United States are likely to move Canadian gas away from California. Increased gas deliveries from the Permian Basin to California are expected to replace these supplies.

Liquefied Natural Gas (LNG)

SoCalGas anticipates that re-gasified LNG-based gas will be a significant new source of gas supplies in the U.S. by 2008. Although there is uncertainty about the volume and location of new re-gasification terminals and the operations of existing facilities to receive LNG supplies, SoCalGas expects that approximately 1,000 MMcfd of gas will be available on the North American West Coast by 2008 with approximately 800 MMcdf potentially available to Southern California's gas customers. One re-gasification facility is already under construction in Baja California, Mexico, and it is expected to have an initial capacity of 1,000 MMcf/d in 2008 with plans for future expansion. At this point it is uncertain as to how many other re-gasification facilities will actually be built and where they will be located although several re-gasification terminals are in the planning and permitting stage on the West Coast of North America.

GAS PRICE FORECAST

MARKET CONDITION

The upward pressure on natural gas prices has been significant since the beginning of the new millennium mainly due to a combination of unprecedented oil prices, strong growth in natural gas consumption particularly in the electric generation sector, and stagnant North American gas production. Yearly average natural gas prices in 2005 have risen a total of 330 percent since 1995 and are expected to remain elevated and volatile as increased demand is faced with limited new supply. In the long run, it is the general belief of industry experts that the long-term prospects for North American production, including unconventional gas supplies (shale, tight sands, and coal bed methane), will not be able to offset declines in conventional production. In addition, slow progress on the Alaska Arctic and Canadian Mackenzie Delta pipelines will not add significant supply until after 2015. Liquid Natural gas (LNG) is expected to relieve some of the pressure by 2008; however, world-wide demand and prices will most likely dictate the availability of LNG supplies to North America.

Therefore, industry experts prognosticate that gas prices can be expected to remain relatively high and volatile during the forecast period due to the growing economy and declining North American production. This expectation is corroborated by the New York Mercantile Exchange's (NYMEX) natural gas futures prices and by industry experts' opinions in the public and private sectors.

DEVELOPMENT OF THE FORECAST

The base natural gas price forecast used to develop demand forecast was prepared according to the Commission-mandated methodology described in Decision D.05-12-042 for the Renewables Portfolio Standard 2005 Market Price Referent. The 20-year gas price forecast is composed of forecasts for three time frames, each utilizing a different method. The short-term forecast from 2006 to 2011 was derived from the last 22-trading days of the NYMEX natural gas futures prices in March 2006. The long-term forecast from 2015 to 2025 was averaged from three forecasts from public and private sources that relied on fundamentals-based models, and the intermediate-term forecast from 2012 to 2014 was a straight blend between the short-term and long-term forecasts.

It is important to recognize that natural gas prices have been much more volatile than in the past, and no price forecast can be expected to account for all uncertainties. However, both the NYMEX gas futures market and industry experts expect prices will moderate after 2008 mostly due to the completion of several LNG re-gasification projects currently under construction in North America.

RETAIL CORE PEAK DAY DEMAND

SoCalGas plans and designs its system to provide continuous service to its core customers under an extreme peak day event. The extreme peak day design criteria is defined as a 1-in-35 likelihood event; this correlates to a system average temperature of 38 degrees Fahrenheit. Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The following table provides an illustration of how storage and flowing supplies can meet the growth in forecasted retail core peak day demand.

Retail Core Peak Day Demand and Supply Requirements (MMcf/Day)

	2006	2007	2008	2010
Retail Core Demand	3,537	3,536	3,633	3,788
Firm Storage Withdrawal	1,963	1,963	2,016	2,102
Required Flowing Supplies	1,574	1,573	1,617	1,686

Notes:
Firm withdrawal and flowing supply requirements are shown to increase proportionally with demand growth beginning in 2006 and afterwards. Firm withdrawal plus firm pipeline supplies must be sufficient to meet peak day operating requirements.

2006 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2001 TO 2005

Line	CAPACITY AVAILABLE		2001	2002	2003	2004	2005	Line
1	California Source Gas							1
	Out-of-State Gas							
2	California Offshore -POPCO / PIOC							2
3	El Paso Natural Gas Co.							3
4	Transwestern Pipeline Co.							4
5	Kern / Mojave							5
6	PGT / PG&E							6
7	Other							7
8	Total Out-of-State Gas							8
9	TOTAL CAPACITY AVAILABLE							9
	GAS SUPPLY TAKEN							
10	California Source Gas		388	300	241	291	274	10
	Out-of-State Gas							
11	Pacific Interstate Companies		-	-	-	-	-	11
12	Other Out-of-State		2,907	2,488	2,378	2,429	2,220	12
13	Total Out-of-State Gas		2,907	2,488	2,378	2,429	2,220	13
14	TOTAL SUPPLY TAKEN		3,295	2,788	2,619	2,720	2,494	14
15	Net Underground Storage Withdrawal		(70)	11	(11)	(22)	(11)	15
16	TOTAL THROUGHPUT (1)		3,225	2,799	2,608	2,698	2,483	16
	DELIVERIES BY END-USE (2)							
17	Core	Residential	724	707	666	699	660	17
18		Commercial	205	205	200	215	211	18
19		Industrial	57	57	57	63	65	19
20		NGV	12	15	15	17	20	20
21		Subtotal	998	984	938	994	956	21
22	Noncore	Commercial	61	65	62	60	60	22
23		Industrial	338	368	349	356	344	23
24		EOR Steaming	29	39	42	35	34	24
25		Electric Generation	1,257	869	789	781	676	25
26		Subtotal	1,685	1,342	1,242	1,232	1,114	26
27	Wholesale/International		475	425	377	427	393	27
28	Co. Use & LUAF (3)		66	48	51	45	20	28
29	SYSTEM TOTAL-THROUGHPUT (1)		3,225	2,799	2,608	2,698	2,483	29
	TRANSPORTATION AND EXCHANGE							
30	Core	All End Uses	26	14	10	7	7	30
31	Noncore	Commercial/Industrial	393	427	403	414	404	31
32		EOR Steaming	29	39	42	35	34	32
33		Electric Generation	1,255	869	788	781	676	33
34		Subtotal-Retail	1,703	1,348	1,243	1,236	1,121	34
35	Wholesale/International		475	425	377	427	393	35
36	TOTAL TRANSPORTATION & EXCHANGE		2,178	1,773	1,620	1,663	1,514	36
	CURTAILMENT (RETAIL & WHOLESALE)							
37		Core	0	0	0	0	0	37
38		Noncore	0	0	0	0	0	38
39		TOTAL - Curtailment	0	0	0	0	0	39
40	REFUSAL		0	0	0	0	0	40

NOTES:

	2001	2002	2003	2004	2005
(1) Exclude own-source gas supply of procurement by Edison and City of Long Beach.	11	11	4	6	2

(2) Deliveries by end-use includes sales, transportation, and exchange volumes.
(3) Data includes effect of prior period adjustments.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2006 THRU 2010

AVERAGE TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2006	2007	2008	2009	2010	LINE
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	LNG Capacity 4/		0	0	800	800	800	8
9	Total Out-of-State Gas		3,565	3,565	4,365	4,365	4,365	9
10	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	4,675	4,675	4,675	10
	GAS SUPPLY TAKEN							
11	California Source Gas		310	310	310	310	310	11
12	Out-of-State		2,335	2,343	2,400	2,303	2,232	12
13	TOTAL SUPPLY TAKEN		2,645	2,653	2,710	2,613	2,542	13
14	Net Underground Storage Withdrawal		0	0	0	0	0	14
15	TOTAL THROUGHPUT 1/, 2/		2,645	2,653	2,710	2,613	2,542	15
	REQUIREMENTS FORECAST BY END-USE 3/							
16	CORE	Residential	700	698	701	708	711	16
17		Commercial	218	216	215	215	213	17
18		Industrial	64	62	61	61	59	18
19		NGV	20	21	22	23	24	19
20		Subtotal-CORE	1,001	997	999	1,007	1,008	20
21	NONCORE	Commercial	57	57	57	58	58	21
22		Industrial	349	344	343	344	343	22
23		EOR Steaming	35	35	30	20	20	23
24		Electric Generation (EG)	745	779	833	725	671	24
25		Subtotal-NONCORE	1,186	1,214	1,263	1,146	1,092	25
26	WHOLESALE &	Core	180	181	177	173	175	26
27	INTERNATIONAL	Noncore Excl. EG	43	43	44	44	44	27
28		Electric Generation (EG)	185	168	175	192	174	28
29		Subtotal-WHOLESALE & INTL	409	392	397	410	393	29
30		Co. Use & LUAF	50	50	51	49	48	31
31	SYSTEM TOTAL THROUGHPUT /1		2,645	2,653	2,710	2,613	2,542	32
	TRANSPORTATION AND EXCHANGE							
32	CORE	All End Uses	8	8	8	8	8	33
33	NONCORE	Commercial/Industrial	406	401	401	402	402	34
34		EOR Steaming	35	35	30	20	20	35
35		Electric Generation (EG)	745	779	833	725	671	36
36		Subtotal-RETAIL	1,193	1,222	1,270	1,154	1,100	37
	WHOLESALE &							
37	INTERNATIONAL	All End Uses	409	392	397	410	393	38
38	TOTAL TRANSPORTATION & EXCHANGE		1,602	1,614	1,667	1,564	1,494	39
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	40
40		Noncore	0	0	0	0	0	41
41		TOTAL - Curtailment	0	0	0	0	0	42
	NOTES:							
	1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2011 THRU 2025

AVERAGE TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2011	2012	2015	2020	2025	LINE
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	LNG Capacity 4/		800	800	800	800	800	8
9	Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	9
10	TOTAL CAPACITY AVAILABLE /1		4,675	4,675	4,675	4,675	4,675	10
	GAS SUPPLY TAKEN							
11	California Source Gas		310	310	310	310	310	11
12	Out-of-State		2,157	2,170	2,199	2,243	2,403	12
13	TOTAL SUPPLY TAKEN		2,467	2,480	2,509	2,553	2,713	13
14	Net Underground Storage Withdrawal		0	0	0	0	0	14
15	TOTAL THROUGHPUT 1/, 2/		2,467	2,480	2,509	2,553	2,713	15
	REQUIREMENTS FORECAST BY END-USE 3/							
16	CORE	Residential	716	718	734	744	765	16
17		Commercial	211	207	198	176	170	17
18		Industrial	58	57	52	43	39	18
19		NGV	25	25	27	30	33	19
20		Subtotal-CORE	1,010	1,008	1,011	994	1,008	20
21	NONCORE	Commercial	59	59	60	60	61	21
22		Industrial	335	335	337	328	323	22
23		EOR Steaming	20	20	20	20	20	23
24		Electric Generation (EG)	603	612	636	692	806	24
25		Subtotal-NONCORE	1,016	1,025	1,053	1,100	1,210	25
26	WHOLESALE &	Core	176	176	179	185	194	26
27	INTERNATIONAL	Noncore Excl. EG	45	44	45	46	47	27
28		Electric Generation (EG)	174	179	174	181	204	28
29		Subtotal-WHOLESALE & INTL	394	399	398	411	444	29
30		Co. Use & LUAF	46	47	47	48	51	31
31	SYSTEM TOTAL THROUGHPUT /1		2,467	2,480	2,509	2,553	2,713	32
	TRANSPORTATION AND EXCHANGE							
32	CORE	All End Uses	8	8	7	7	7	33
33	NONCORE	Commercial/Industrial	394	394	397	388	384	34
34		EOR Steaming	20	20	20	20	20	35
35		Electric Generation (EG)	603	612	636	692	806	36
36		Subtotal-RETAIL	1,024	1,033	1,060	1,107	1,217	37
	WHOLESALE &							
37	INTERNATIONAL	All End Uses	394	399	398	411	444	38
38	TOTAL TRANSPORTATION & EXCHANGE		1,418	1,432	1,458	1,518	1,661	39
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	40
40		Noncore	0	0	0	0	0	41
41		TOTAL - Curtailment	0	0	0	0	0	42

NOTES:

	2011	2012	2015	2020	2025
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2006 THRU 2010

COLD TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2006	2007	2008	2009	2010	LINE
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	LNG Capacity 4/		0	0	800	800	800	8
9	Total Out-of-State Gas		3,565	3,565	4,365	4,365	4,365	9
10	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	4,675	4,675	4,675	10
	GAS SUPPLY TAKEN							
11	California Source Gas		310	310	310	310	310	11
12	Out-of-State		2,445	2,453	2,511	2,413	2,342	12
13	TOTAL SUPPLY TAKEN		2,755	2,763	2,821	2,723	2,652	13
14	Net Underground Storage Withdrawal		0	0	0	0	0	14
15	TOTAL THROUGHPUT 1/, 2/		2,755	2,763	2,821	2,723	2,652	15
	REQUIREMENTS FORECAST BY END-USE 3/							
16	CORE	Residential	775	774	777	785	788	16
17		Commercial	231	228	227	228	226	17
18		Industrial	65	64	63	62	61	18
19		NGV	20	21	22	23	24	19
20		Subtotal-CORE	1,091	1,087	1,089	1,098	1,099	20
21	NONCORE	Commercial	57	57	57	58	58	21
22		Industrial	349	344	343	344	343	22
23		EOR Steaming	35	35	30	20	20	23
24		Electric Generation (EG)	745	779	833	725	671	24
25		Subtotal-NONCORE	1,186	1,214	1,263	1,146	1,092	25
26	WHOLESALE &	Core	198	199	197	190	192	26
27	INTERNATIONAL	Noncore Excl. EG	43	43	44	44	44	27
28		Electric Generation (EG)	185	168	175	192	174	28
29		Subtotal-WHOLESALE & INTL	426	410	416	427	411	29
30		Co. Use & LUAF	52	52	53	51	50	31
31	SYSTEM TOTAL THROUGHPUT /1		2,755	2,763	2,821	2,723	2,652	32
	TRANSPORTATION AND EXCHANGE							
32	CORE	All End Uses	8	8	8	8	8	33
33	NONCORE	Commercial/Industrial	406	401	401	402	402	34
34		EOR Steaming	35	35	30	20	20	35
35		Electric Generation (EG)	745	779	833	725	671	36
36		Subtotal-RETAIL	1,194	1,223	1,271	1,155	1,101	37
	WHOLESALE &							
37	INTERNATIONAL	All End Uses	426	410	416	427	411	38
38	TOTAL TRANSPORTATION & EXCHANGE		1,620	1,632	1,687	1,582	1,511	39
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	40
40		Noncore	0	0	0	0	0	41
41		TOTAL - Curtailment	0	0	0	0	0	42

NOTES:

		2006	2007	2008	2009	2010
1/	Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2011 THRU 2025

COLD TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2011	2012	2015	2020	2025	LINE
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	LNG Capacity 4/		800	800	800	800	800	8
9	Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	9
10	TOTAL CAPACITY AVAILABLE /1		4,675	4,675	4,675	4,675	4,675	10
	GAS SUPPLY TAKEN							
11	California Source Gas		310	310	310	310	310	11
12	Out-of-State		2,267	2,280	2,311	2,355	2,518	12
13	TOTAL SUPPLY TAKEN		2,577	2,590	2,621	2,665	2,828	13
14	Net Underground Storage Withdrawal		0	0	0	0	0	14
15	TOTAL THROUGHPUT 1/, 2/		2,577	2,590	2,621	2,665	2,828	15
	REQUIREMENTS FORECAST BY END-USE 3/							
16	CORE	Residential	794	796	813	825	848	16
17		Commercial	224	220	210	186	180	17
18		Industrial	60	58	54	44	40	18
19		NGV	25	25	27	30	33	19
20		Subtotal-CORE	1,102	1,099	1,104	1,086	1,102	20
21	NONCORE	Commercial	59	59	60	60	61	21
22		Industrial	335	335	337	328	323	22
23		EOR Steaming	20	20	20	20	20	23
24		Electric Generation (EG)	603	612	636	692	806	24
25		Subtotal-NONCORE	1,016	1,025	1,053	1,100	1,210	25
26	WHOLESALE &	Core	193	193	196	203	213	26
27	INTERNATIONAL	Noncore Excl. EG	45	44	45	46	47	27
28		Electric Generation (EG)	174	179	174	181	204	28
29		Subtotal-WHOLESALE & INTL	411	417	415	429	463	29
30		Co. Use & LUAF	48	49	49	50	53	31
31	SYSTEM TOTAL THROUGHPUT /1		2,577	2,590	2,621	2,665	2,828	32
	TRANSPORTATION AND EXCHANGE							
32	CORE	All End Uses	8	8	8	8	8	33
33	NONCORE	Commercial/Industrial	394	394	397	388	384	34
34		EOR Steaming	20	20	20	20	20	35
35		Electric Generation (EG)	603	612	636	692	806	36
36		Subtotal-RETAIL	1,024	1,034	1,061	1,108	1,217	37
38	WHOLESALE &							38
37	INTERNATIONAL	All End Uses	411	417	415	429	463	39
38	TOTAL TRANSPORTATION & EXCHANGE		1,436	1,450	1,476	1,537	1,680	40
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	41
40		Noncore	0	0	0	0	0	42
41		TOTAL - Curtailment	0	0	0	0	0	43

NOTES:

	2011	2012	2015	2020	2025
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008.

2006 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT

CITY OF LONG BEACH MUNICIPAL GAS & OIL DEPARTMENT

The annual gas supply and requirements for the Long Beach Gas & Oil Department (Long Beach) are shown on the following tables for the years 2005 through 2025. Long Beach prepared all forecasted requirements.

Serving approximately 145,000 customers, Long Beach is the largest California municipal gas utility and the fifth largest municipal gas utility in the United States. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's customer load profile is 50 percent residential and 50 percent commercial/industrial.

As a municipal utility, Long Beach's rates and policies are established by the City Council, which acts as the regulatory authority. The City Charter requires the gas utility to establish its rates comparable to the rates charged by surrounding gas utilities for similar types of service.

Long Beach receives a small amount of its gas supply directly into its pipeline system from local production fields that are located within Long Beach's service territory, as well as offshore. Previous to 2002, Long Beach received one third of its gas supply through local production. The majority of Long Beach supplies are purchased at the California border, primarily from the Southwestern United States. Long Beach, as a wholesale customer, receives intrastate transmission service for this gas from SoCalGas.

2006 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT
TABULAR DATA

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2001 THRU 2005

LINE	GAS SUPPLY AVAILABLE	2001	2002	2003	2004	2005	LINE
	California Source Gas						
1	Regular Purchases						1
2	Received for Exchange/Transport						2
3	Total California Source Gas						3
4	Purchases from Other Utilities						4
	Out-of-State Gas						
5	Pacific Interstate Companies						5
6	Additional Core Supplies						6
7	Incremental Supplies						7
8	Out-of-State Transport						8
9	Total Out-of-State Gas						9
10	Subtotal						10
11	Underground Storage Withdrawal						11
12	GAS SUPPLY AVAILABLE						12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	10	11	11	10	4	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	10	11	11	10	4	15
16	Purchases from Other Utilities	0	0	0	0	0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0	0	0	0	0	17
18	Additional Core Supplies	0	0	0	0	0	18
19	Incremental Supplies	27	24	21	21	29	19
20	Out-of-State Transport	0	0	0	0	0	20
21	Total Out-of-State Gas	27	24	21	21	29	21
22	Subtotal	37	35	32	31	33	22
23	Underground Storage Withdrawal	0	0	0	0	0	23
24	TOTAL Gas Supply Taken & Transported	37	35	32	31	33	24

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2001 THRU 2005

LINE	ACTUAL DELIVERIES BY END-USE		2001	2002	2003	2004	2005	LINE
1	CORE	Residential	18	17	17	16	16	1
2	CORE/NONCORE	Commercial	7	7	7	7	7	2
3	CORE/NONCORE	Industrial	10	9	7	6	7	3
4		Subtotal	36	33	31	29	30	4
5	NON CORE	Non-EOR Cogeneration	0.1	0.0	0.1	0.2	3	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	0	0	0	0	0	7
8		Subtotal	0.1	0.0	0.1	0.2	3	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal-WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0.5	1	1	0.5	0.0	13
14		Subtotal-END USE	36	35	32	30	33	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL-THROUGHPUT		36	35	32	30	33	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	N/A	N/A	N/A	N/A	N/A	18
19		Non-EOR Cogeneration	N/A	N/A	N/A	N/A	N/A	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	27	24	21	21	29	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		27	24	21	21	29	24
	ACTUAL CURTAILMENT							
25		Residential	0	0	0	0	0	25
26		Commercial/Industrial	0	0	0	0	0	26
27		Non-EOR Cogeneration	0	0	0	0	0	27
28		EOR Cogen. & Steaming	0	0	0	0	0	28
29		Electric Utilites	0	0	0	0	0	29
30		Wholesale	0	0	0	0	0	30
31		TOTAL- Curtailment	0	0	0	0	0	31
32	REFUSAL		0	0	0	0	0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2006 THRU 2010
AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2006	2007	2008	2009	2010	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		2	2	1	2	1	4
5	Out-of-State Gas		31	31	31	31	31	5
6	TOTAL SUPPLY TAKEN		33	33	33	33	32	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		33	33	33	33	32	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	17	17	17	17	17	9
10		Commercial	5	5	5	5	5	10
11		NGV	0.1	0.1	0.1	0.1	0.1	11
12		Subtotal-CORE	22	22	22	22	22	12
13	NONCORE	Industrial	8	8	8	8	8	13
14		Non-EOR Cogeneration	3	2	3	3	3	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	11	10	11	11	10	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		33	33	33	33	32	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	23	23	23	23	23	22
23	NONCORE	Industrial	8	8	8	8	8	23
24		Non-EOR Cogeneration	3	2	3	3	3	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	11	10	11	11	10	27
28	TOTAL TRANSPORTATION		34	34	34	34	34	28

(1) Requirement forecast by end-use includes sales and transportation volumes.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2011 THRU 2025
AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2011	2012	2015	2020	2025	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		1	1	1	2	1	4
5	Out-of-State Gas		31	31	31	31	31	5
6	TOTAL SUPPLY TAKEN		32	32	32	33	33	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		32	32	32	33	33	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	16	17	17	17	17	9
10		Commercial	5	5	5	5	5	10
11		NGV	0.1	0.1	0.1	0.1	0.1	11
12		Subtotal-CORE	22	22	22	22	22	12
13	NONCORE	Industrial	8	8	8	8	8	13
14		Non-EOR Cogeneration	3	3	3	3	3	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	11	11	11	11	11	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		32	32	32	32	32	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	23	23	23	23	23	22
23	NONCORE	Industrial	8	8	8	8	8	23
24		Non-EOR Cogeneration	3	3	3	3	3	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	11	11	11	11	11	27
28	TOTAL TRANSPORTATION		34	34	34	34	34	28

(1) Requirement forecast by end-use includes sales and transportation volumes.

2006 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

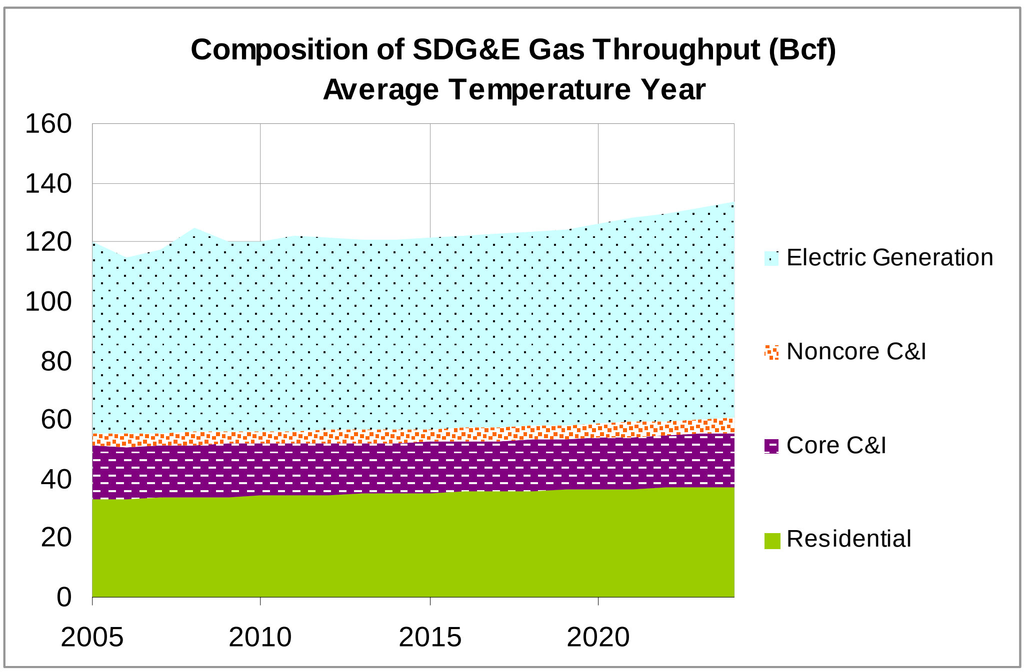
San Diego Gas & Electric Company (SDG&E) is a combined gas and electric distribution utility serving more than three million people in San Diego and southern portions of Orange counties. SDG&E delivers natural gas to over 815,000 customers in San Diego County, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2005 were approximately 118 billion cubic feet (Bcf), which is an average of over 323 million cubic feet per day (MMcf/day). These 2005 deliveries corresponded to a modest increase in gas usage by power generators within SDG&E's service territory compared to earlier years. Additionally Miramar, a 45 MW peaking unit, began producing power commercially on August 1, 2005 and Palomar, a 540 MW plant, began commercial operation on April 1, 2006. Both units are located in SDG&E's service territory and are fueled by natural gas.

GAS DEMAND

OVERVIEW

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for the San Diego County gas service area. From 2005 to 2025, the county's inflation-adjusted Gross Product is expected to grow at a healthy 3.4% per year. (Gross Product is the local equivalent of national Gross Domestic Product, a measure of the total economic output of the area economy.) Local employment is expected to grow at an average rate of 1.5% annually to 2025; however, the subset of industrial (mining and manufacturing) jobs is projected to shrink 0.1% per year over the same period. The number of SDG&E gas meters is expected to increase an average of 1.5% annually over the next 20 years.

This projection of natural gas requirements, excluding electric generation (EG) demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Non-EG gas demand is projected to increase by 11% between 2006 and 2025. Assumptions for SDG&E's gas transport requirements for EG are included as part of the wholesale market sector description for Southern California Gas Company.



MARKET SECTORS

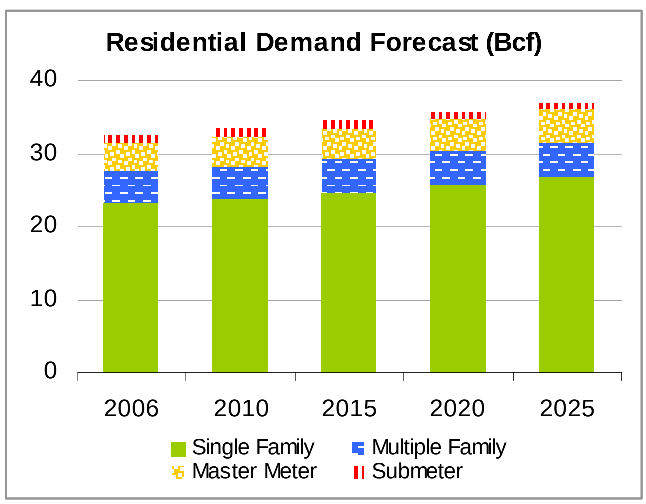
Residential

The total residential customer count for SDG&E consists of four residential segment types. These are single family and multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 793,000 in 2005. This total reflects a 12,300 meter increase relative to the 2004 total. The overall observed 2004-2005 residential meter growth was 1.5%.

From 2005 through 2025, average residential meters are forecasted to grow at an annual rate of 1.6%. By the year 2025, the residential meters are expected to exceed 1 million meters.

Residential demand adjusted for average temperature conditions totaled 33 Bcf in 2005. The unadjusted residential gas demand was 31 Bcf which is 5.8% less than the temperature-adjusted demand due to warmer than normal weather conditions in the San Diego area. The difference is explained by 12.2% fewer observed Heating Degree Days (HDD) in 2005 from the 2004 annual totals.

Use per meter for all classes of residential customers is forecasted to decline due to the expected energy savings from tightened building and appliance standards and CPUC-authorized energy efficiency programs. During the forecast period, the weather normalized annual average use per residential customer is expected to fall from 416 therms per customer in 2006 to 353 therms in 2025. The change reflects a 15% decline from the 416 therms per customer in 2006.

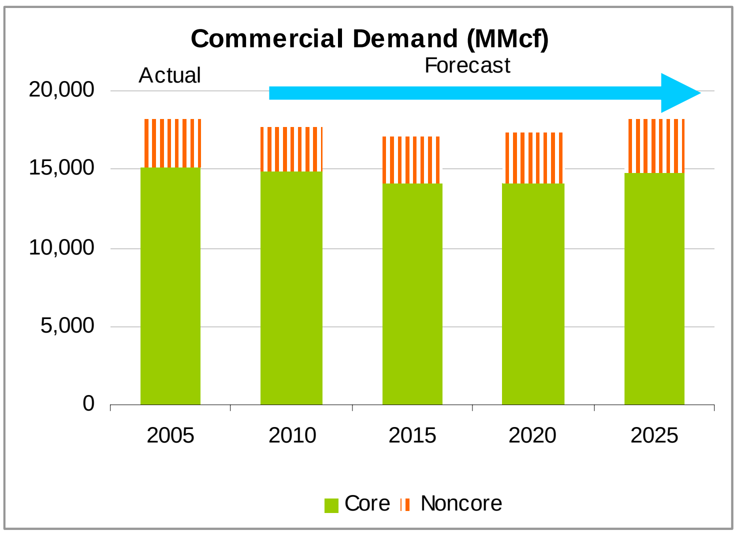


In 2005, residential demand was 33 Bcf and is forecast to increase to 38 BCF or 15 percent in 2025. The difference reflects an average increase of .23 Bcf per year.

The projected residential natural gas demand will be influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in the building shell design, appliance efficiency and CPUC-authorized EE programs.

Commercial

On a temperature-adjusted basis, core commercial market demand in 2005 totaled just below 15.2 Bcf. Although the number of core commercial customers is growing, core commercial market gas demand is forecast to decrease very modestly due to CPUC-mandated energy efficiency programs by about 0.1% per year over the next 20 years, reaching 14.8 Bcf in 2025. The effect of the CPUC-authorized energy efficiency programs leads to reduced Core Commercial gas demand through 2018; thereafter, core commercial gas demand is forecast to increase as the impact of growing employment and declining real gas rates begin to offset the conservation effect of EE programs.

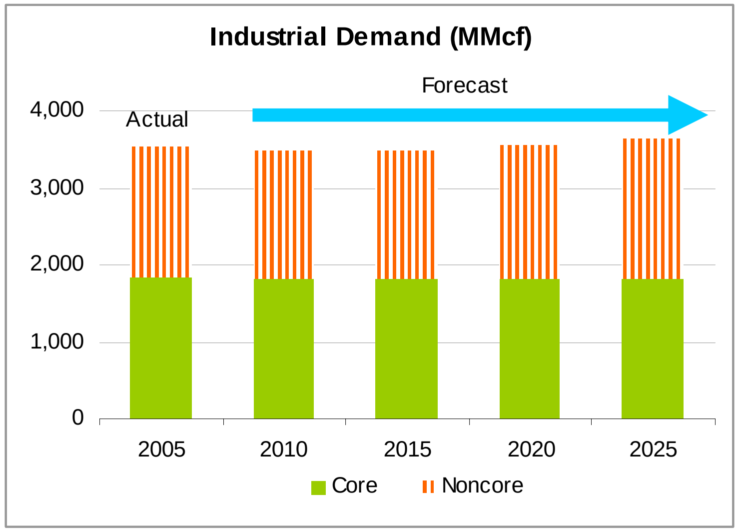


The non-core commercial load was volatile in 2005 due to unprecedented high natural gas prices. This market has a small number of customers, and the behavior of a few large customers can lead to wide load swings. The non-core commercial load in 2005 was 3.0 Bcf, or a 17% increase from 2004 due to the migration of load from the cogeneration market to the commercial market segment. Over the next 20 years, gas demand in this market is projected to grow, mostly driven by increased economic activity and employment in the service sector. The non-core commercial load is projected to increase by 3.3 BCF or 28%, between 2006 and 2025, an average annual increase of 1.3%.

Industrial

In 2005, temperature-adjusted core industrial demand was 1.83 Bcf. Core industrial market demand is projected to remain essentially flat from 2006 to 2025. This result is due to almost no growth in industrial production and the increased use of more energy-efficient gas equipment in the industrial sector.

The non-core industrial load in 2005 was 1.7 Bcf and is expected to grow slowly at an average rate of 0.3% per year, to 1.8 Bcf by 2025. This growth is led by increased economic activity and employment in the manufacturing sector moderated by CPUC-mandated energy efficiency programs' conservation effects.



Cogeneration

The self-generation load in 2005 dropped 12% from the previous year due to high natural gas prices and temporary shut downs of several large plants for maintenance. This load is projected to grow according to the added load projected by the CEC for the *2005 Integrated Energy Resource Plan* in the San Diego service area. The annual growth rate during the forecast period from 2006 to 2025 is expected to be about 0.4%; with most of the growth expected to occur in the next few years, then leveling off after 2007.

Natural Gas Vehicles (NGV)

The NGV market is forecast to continue to grow due to federal, state and local incentives for the purchase of school buses, shared rides and Government vehicles. Throughput growth is aided by the increased reliability of the refueling infrastructure and a substantial positive differential between gasoline and compressed natural gas (CNG) prices. At the end of 2005, there were 33 NGV fueling stations servicing approximately 2,000 vehicles in the San Diego County area. However, the rate of growth in new customers and load is expected to moderate, since transit fleets, which account for approximately 56% of the market, are close to their fleet saturation levels.

SDG&E recently introduced a new tariff for home NGV refueling. Currently, there is one type of known home refueling appliance unit on the market in the SDG&E service territory. This unit is manufactured by FuelMaker and it allows customers to refuel their NGVs at home using their existing residential gas service meter. We expect that this product will enhance the growth of the NGV market by providing support to the growing NGV station infrastructure.

GAS SUPPLY

SDG&E continues to procure and deliver natural gas for its customers, with its current core portfolio consisting of supplies from western Canada, the Rocky Mountains, the US Southwest's San Juan and Permian basins and spot market purchases at the California border. In response to the Commission's Gas Market OIR Decision (D.04-09-022), SDG&E has contracted for 100% of its interstate pipeline capacity to provide supply diversity and flexibility for the future. Gas procurement will continue to be subject to a performance-based incentive mechanism that allows for the reasonableness of gas purchases to be judged against a market benchmark.

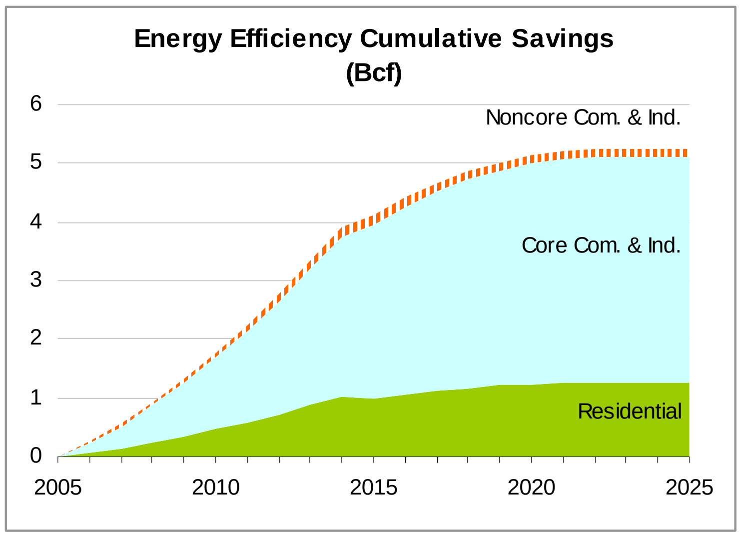
SDG&E has long-term contracts with El Paso Natural Gas Company for a total of 46.3 MMcf/day of firm transportation capacity, 7 MMcf/day of firm transportation capacity on Kern River Gas Transmission, and about 51 MMcf/day of firm transportation capacity from Canada under two separate contracts – 53.1 MMcf/day on the TransCanada Nova and TransCanada BC systems through Canada to the U.S.-Canadian border, and 51.2 MMcf/day on the TransCanada GTN/PG&E (1993 Expansion) pipeline systems from the Canadian border to California. Underground storage inventory rights for SDG&E's core gas customers totaling 7,822,461 Dekatherms (Dth) are specified in the current one-year natural gas service contract with SoCalGas, with these storage rights increasing to 9,000,000 Dekatherms (Dth) beginning April 1, 2007. As the gas industry continues to change in response to market dynamics, however, SDG&E's firm pipeline and storage capacity needs and supply portfolio mix can be expected to be revised to ensure customer service reliability at reasonable costs.

There is expected to be sufficient supply deliverability to SDG&E's gas system from the SoCalGas pipeline system and storage facilities. Gas delivery is made primarily through the Moreno-to-San Diego transmission pipeline system.

ENERGY EFFICIENCY PROGRAMS

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage while still maintaining a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the Energy Efficiency programs.

The cumulative net Energy Efficiency load impact forecast for selected years is provided in Tables 1 and 2. The net load impact includes all Energy Efficiency programs that San Diego Gas & Electric Company (SDG&E) has forecasted to implement in the years 2006 through 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.



Savings reported are for measures installed under SDG&E's Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SDG&E's Energy Efficiency programs, and only for the measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2005 with a lifetime of 10 years is only included in the forecast through 2014. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included in the Energy Efficiency forecast.

Details of SDG&E's' 2006-2008 Energy Efficiency program portfolio are contained in SDG&E's' Advice Letter 1769-E/1591-G, which was submitted on February 1, 2006 and became effective March 3, 2006.

Notes:

1. Energy Efficiency load impacts include 2003-2004 program savings, but do not include pre-2003 program savings.
2. "Hard" impacts include measures requiring a physical equipment modification or replacement.
3. SDG&E does not include "soft" impacts, e.g., energy management services type measures.
4. The assumed average measure life is 10 years.

PEAK DAY DEMAND AND DELIVERABILITY

SDG&E plans and designs its system to provide continuous service to its core customers under an extreme peak day event. The extreme peak day design criteria is defined as a 1-in-35 likelihood event; this correlates to a system average temperature of 41.4 degrees Fahrenheit. Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The following table provides an illustration of how storage and flowing supplies can meet the growth in forecasted retail core peak day demand.

Retail Core Peak Day Demand and Supply Requirements
(MMcf/Day)

	2006	2007	2008	2010
Retail Core Demand	440	441	458	483
Firm Storage Withdrawal	226	227	235	248
Required Flowing Supplies	214	215	223	235

Notes:
Firm withdrawal and flowing supply requirements are shown to increase proportionally with demand growth beginning in 2006 and afterwards. Firm withdrawal plus firm pipeline supplies must be sufficient to meet peak day operating requirements.

2006 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

ANNUAL GAS SUPPLY TAKEN
RECORDED YEAR 2001-2005
(MMCF/D)

LINE	GAS SUPPLY TAKEN	2001	2002	2003	2004	2005	LINE
	California Source Gas						
1	Regular Purchases	9	3	3	5	6	1
2	Received for Exchange/Transport	0	0	0	0	0	2
3	Total California Source Gas	9	3	3	5	6	3
4	Purchases from Other Utilities	0	0	0	0	0	4
5	Out-of-State Gas						5
6	Pacific Interstate Companies	0	0	0	0	0	6
7	Additional Core Supplies	0	0	0	0	0	7
8	Supplemental Supplies-Utility	131	122	133	145	143	8
9	Out-of-State Transport-Others	284	247	182	213	174	9
10	Total Out-of-State Gas	415	368	314	358	317	10
11	TOTAL Gas Supply Taken & Transported	424	371	317	363	323	11

ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2001-2005
(MMCF/D)

LINE	ACTUAL DELIVERIES BY END-USE		2001	2002	2003	2004	2005	LINE
1	CORE	Residential	93	92	87	92	86	1
2		Commercial	46	49	47	48	48	2
3		Industrial	0	0	0	0	0	3
4	*Subtotal -*	*CORE*	139	141	134	140	134	4
5	NONCORE	Commercial	0	0	0	0	0	5
6		Industrial	12	10	10	10	10	6
7		Non-EOR Cogen/EG	276	234	172	203	163	7
8		Electric Utilities	0	0	0	0	0	8
9	*Subtotal -*	*NONCORE*	288	244	183	213	174	9
10	WHOLESALE	All End Uses	0	0	0	0	0	10
11	*Subtotal -*	*Co Use & LUAF*	-2	-14	1	10	15	11
12	Sytem Total Throughput		424	371	317	363	323	12
	ACTUAL TRANSPORT & EXCHANGE							
13	CORE	Residential	0	0	0	0	0	13
14		Commercial	6	7	2	2	2	14
15	NONCORE	Industrial	6	8	9	9	9	15
16		Non-EOR Cogen/EG	272	232	171	202	162	16
17		Electric Utilities	0	0	0	0	0	17
18	*Subtotal -*	*RETAIL*	284	247	182	213	174	18
19	WHOLESALE	All End Uses	0	0	0	0	0	19
20	Total Transport and Exchange		284	247	182	213	174	20
	Storage							
21		Storage Injection	12	11	20	21	12	21
22		Storage Withdrawal	7	16	18	10	21	22
	ACTUAL CURTAILMENT							
23		Residential	0	0	0	0	0	23
24		Com/Indl & Cogen	0	0	0	0	0	24
25		Electric Generation	3	0	0	0	0	25
26	Total Curtailment		3	0	0	0	0	26
27	REFUSAL		0	0	0	0	0	27

ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes

	2001	2002	2003	2004	2005
MMbtu/Mcf:	1.018	1.014	1.012	1.012	1.015

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2006 THRU 2010

AVERAGE TEMPERATURE YEAR

LINE			2006	2007	2008	2009	2010	LINE
	FIRM CAPACITY AVAILABLE 2/ & 3/							
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		334	318	325	347	333	10
11	TOTAL SUPPLY TAKEN		334	318	325	347	333	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		334	318	325	347	333	13
	REQUIREMENTS FORECAST BY END-USE 1/							
14	CORE	Residential	91	91	91	92	93	14
15		Commercial	41	41	41	41	41	15
16		Industrial	5	5	5	5	5	16
17		NGV	3	3	3	3	3	17
18		Subtotal-CORE	140	140	140	141	142	18
19	NONCORE	Commercial	7	7	7	7	7	19
20		Industrial	5	4	5	5	5	20
21		Electric Generation (EG)	178	163	169	190	175	21
22		Subtotal-NONCORE	190	174	181	202	187	22
23		Co. Use & LUAF	4	4	4	4	4	23
24	SYSTEM TOTAL THROUGHPUT		334	318	325	347	333	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	3	3	3	3	3	25
26	NONCORE	Commercial/Industrial	11	11	11	11	11	26
27		Electric Generation (EG)	178	163	169	189	175	28
28	TOTAL TRANSPORTATION & EXCHANGE		192	177	183	203	189	29
	CURTAILMENT							
29		Core	0	0	0	0	0	30
30		Noncore	0	0	0	0	0	31
31		TOTAL - Curtailment	0	0	0	0	0	32

NOTES:
1/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
2/ Firm capacity uder contrat by SDG&E in 2006.
3/ For 2007 and after, assume capacity at same levels for 2006.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2011 THRU 2025

AVERAGE TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE 2/ & 3/		2011	2012	2015	2020	2025	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		334	337	334	345	371	10
11	TOTAL SUPPLY TAKEN		334	337	334	345	371	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		334	337	334	345	371	13
	REQUIREMENTS FORECAST BY END-USE 1/							
14	CORE	Residential	94	94	96	99	103	14
15		Commercial	41	40	39	39	41	15
16		Industrial	5	5	5	5	5	16
17		NGV	3	3	3	4	4	17
18		Subtotal-CORE	143	142	143	147	153	18
19	NONCORE	Commercial	8	8	8	8	9	19
20		Industrial	4	4	4	5	5	20
21		Electric Generation (EG)	175	179	175	181	200	21
22		Subtotal-NONCORE	187	191	187	194	214	22
23		Co. Use & LUAF	4	4	4	4	4	23
24	SYSTEM TOTAL THROUGHPUT		334	337	334	345	371	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	3	3	2	3	3	25
26	NONCORE	Commercial/Industrial	11	11	12	12	13	26
27		Electric Generation (EG)	175	179	175	180	200	28
28	TOTAL TRANSPORTATION & EXCHANGE		189	193	189	195	216	29
	CURTAILMENT							
29		Core	0	0	0	0	0	30
30		Noncore	0	0	0	0	0	31
31		TOTAL - Curtailment	0	0	0	0	0	32

NOTES:
1/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
2/ Firm capacity uder contrat by SDG&E in 2006.
3/ For 2007 and after, assume capacity at same levels for 2006.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2006 THRU 2010

COLD TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE 2/ & 3/		2006	2007	2008	2009	2010	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		349	332	339	362	347	10
11	TOTAL SUPPLY TAKEN		349	332	339	362	347	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		349	332	339	362	347	13
	REQUIREMENTS FORECAST BY END-USE 1/							
14	CORE	Residential	103	103	103	104	105	14
15		Commercial	44	43	43	44	43	15
16		Industrial	5	5	5	5	5	16
17		NGV	3	3	3	3	3	17
18		Subtotal-CORE	155	154	154	156	156	18
19	NONCORE	Commercial	7	7	7	7	7	19
20		Industrial	5	4	5	5	5	20
21		Electric Generation (EG)	178	163	169	190	175	21
22		Subtotal-NONCORE	190	174	181	202	187	22
23		Co. Use & LUAF	4	4	4	4	4	23
24	SYSTEM TOTAL THROUGHPUT		349	332	339	362	347	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	3	3	3	3	3	25
26	NONCORE	Commercial/Industrial	11	11	11	11	11	26
27		Electric Generation (EG)	178	163	169	189	175	28
28	TOTAL TRANSPORTATION & EXCHANGE		192	177	183	203	189	29
	CURTAILMENT							
29		Core	0	0	0	0	0	30
30		Noncore	0	0	0	0	0	31
31		TOTAL - Curtailment	0	0	0	0	0	32

NOTES:
1/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
2/ Firm capacity uder contrat by SDG&E in 2006.
3/ For 2007 and after, assume capacity at same levels for 2006.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2011 THRU 2025

COLD TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE 2/ & 3/		2011	2012	2015	2020	2025	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		348	352	348	360	387	10
11	TOTAL SUPPLY TAKEN		348	352	348	360	387	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		348	352	348	360	387	13
	REQUIREMENTS FORECAST BY END-USE 1/							
14	CORE	Residential	106	106	108	112	116	14
15		Commercial	43	43	41	41	43	15
16		Industrial	5	5	5	5	5	16
17		NGV	3	3	3	4	4	17
18		Subtotal-CORE	157	157	157	162	168	18
19	NONCORE	Commercial	8	8	8	8	9	19
20		Industrial	4	4	4	5	5	20
21		Electric Generation (EG)	175	179	175	181	200	21
22		Subtotal-NONCORE	187	191	187	194	214	22
23		Co. Use & LUAF	4	4	4	4	5	23
24	SYSTEM TOTAL THROUGHPUT		348	352	348	360	387	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	3	3	3	3	3	25
26	NONCORE	Commercial/Industrial	11	11	12	12	13	26
27		Electric Generation (EG)	175	179	175	180	200	28
28	TOTAL TRANSPORTATION & EXCHANGE		189	193	190	195	216	29
	CURTAILMENT							
29		Core	0	0	0	0	0	30
30		Noncore	0	0	0	0	0	31
31		TOTAL - Curtailment	0	0	0	0	0	32

NOTES:
1/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
2/ Firm capacity uder contrat by SDG&E in 2006.
3/ For 2007 and after, assume capacity at same levels for 2006.

2006 CALIFORNIA GAS REPORT

LOS ANGELES DEPARTMENT OF WATER AND POWER

LOS ANGELES DEPARTMENT OF WATER AND POWER

The Los Angeles Department of Water and Power (LADWP), the nation's largest municipally owned utility with a service territory of 465 square miles, supplies water and electricity to approximately 3.9 million residents of the nation's second largest city. The array of generation resources is composed of hydro, coal, natural gas, nuclear, and renewables. For calendar year 2005, the LADWP basin gas generation facilities provided approximately 31 percent of the annual generation needs, burning 61.5 Bcf.

LADWP's gas forecast is based on an average annual growth rate of 1.1% in retail electric sales over its service area. Natural gas usage for power generation may not coincide with this growth due to the increase of Renewables and other energy-saving resources. Load growth will be highest in the Commercial Sector taking over leadership from the Residential Sector. This forecast is contingent on the completion of two large new developments being built in Downtown Los Angeles – the Grand Avenue Project and LA Live. The Grand Avenue Project includes 3.2 million square feet of office, retail, restaurant and residential space, while LA Live includes 4 million square feet of entertainment, hotel, retail, restaurant, office and residential space. Residential Sector load growth will flatten momentarily due to housing-led economic slowdown but quickly return to its historical trend. Growth for the Industrial and Miscellaneous Sectors remain relatively unchanged.

Increased implementation of Renewable energy technology within the next 5 years is expected to reduce fossil fuel consumption. The LADWP Board of Commissioners has set the year 2010 to accomplish a goal of 20% energy production to be derived from Renewables. Major components to this source of energy will come from Geothermal, Wind, Biomass, and Solar. As a result of these additions, annual natural gas power generation would represent approximately 19% of the total power mix.

LADWP holds firm capacity rights on three interstate pipelines: Kern River, El Paso, and Mojave pipelines. Both the El Paso and Mojave pipeline contracts are due to expire during the first quarter of 2007.

All the natural gas is procured through spot contracts, one long-term contract (set to expire February 2007), and LADWP owned gas reserves. The gas reserves were acquired in July 2005, and located in Wyoming. Gas delivery from the reserves is about ten percent of the total annual gas consumption.

LADWP's natural gas demand forecast is presented in the following tables for 2006 through 2025 and was developed in March 2006. It was based on the preliminary Fuel and Purchased Power Budget for native load only. The forecast assumes energy is also obtained from outside purchases, Renewable

Energy, Distributed Generation, DSM, and any LADWP programs. Currently, repowering projects are on hold until further assessments are made on the effect they would have on the environment.

2006 CALIFORNIA GAS REPORT

LOS ANGELES DEPARTMENT OF WATER AND POWER
TABULAR DATA

ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2001-2005
MMCF/DAY

LINE	GAS SUPPLY AVAILABLE	2001	2002	2003	2004	2005	LINE
1	California Source Gas						1
	Out-of-State Gas						
2	California Offshore - POPCO/PIOC						2
3	El Paso Natural Gas Co.						3
4	Transwestern Pipeline Co.						4
5	Kern /Mojave						5
6	PGT/PG&E						6
7	Other						7
8	TOTAL Out-of-State Gas						8
9	Subtotal						9
10	Underground Storage Withdrawal						10
11	TOTAL GAS SUPPLY AVAILABLE						11
	GAS SUPPLY TAKEN						
12	California Source Gas	0	0	0	0	0	12
	Out-of-State Gas						
13	Pacific Interstate Companies	0	0	0	0	0	13
14	Other Out-of-State	157	116	149	154	168	14
15	Total Out-of-State Gas	157	116	149	154	168	15
16	Subtotal	157	116	149	154	168	
17	Underground Storage Withdrawal	0	0	0	0	0	17
18	TOTAL GAS SUPPLY TAKEN	157	116	149	154	168	18

ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2001-2005
MMCF/DAY

LINE	ACTUAL DELIVERIES BY END-USE		2001	2002	2003	2004	2005	LINE
1	CORE	Residential	0	0	0	0	0	1
2	CORE/NONCORE	Commercial	0	0	0	0	0	2
3	CORE/NONCORE	Industrial	0	0	0	0	0	3
4		Subtotal	0	0	0	0	0	4
5	NONCORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	157	116	149	154	168	7
8		Subtotal	157	116	149	154	168	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	0	0	0	0	13
14		Subtotal-END USE	157	116	149	154	168	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL THROUGHPUT		157	116	149	154	168	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17	CORE	All End Uses	0	0	0	0	0	17
18	NONCORE	Commercial/Industrial	0	0	0	0	0	18
19		Non-EOR Cogeneration	0	0	0	0	0	19
20		EOR Cogen. & Steaming	0	0	0	0	0	20
21		Electric Utilities	157	116	149	154	168	21
22		Subtotal-RETAIL	157	116	149	154	168	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		157	116	149	154	168	24
	CURTAILMENT (RETAIL & WHOLESALE)							
25		Core	0	0	0	0	0	25
26		Noncore	0	0	0	0	0	26
27		TOTAL-Curtailment	0	0	0	0	0	27
28	REFUSAL		0	0	0	0	0	28

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2006 THRU 2010 - MMCF/DAY
AVERAGE TEMPERATURE YEAR

LINE	GAS SUPPLY AVAILABLE		2006	2007	2008	2009	2010	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2		California Offshore - POPCO/PIOC	0	0	0	0	0	2
3		El Paso Natural Gas Co.	36	0	0	0	0	3
4		Transwestern Pipeline Co.	0	0	0	0	0	4
5		Kern /Mojave	196	146	146	146	146	5
6		PGT/PG&E	0	0	0	0	0	6
7		Other	0	0	0	0	0	7
8	TOTAL Out-of-State Gas		232	146	146	146	146	8
9		Subtotal	232	146	146	146	146	9
10	Underground Storage Withdrawal		0	0	0	0	0	10
11	TOTAL GAS SUPPLY AVAILABLE		232	146	146	146	146	11
	GAS SUPPLY TAKEN							
12	California Source Gas		0	0	0	0	0	12
	Out-of-State Gas							
13		Pacific Interstate Companies	0	0	0	0	0	13
14		Other Out-of-State	165	163	145	137	140	14
15	Total Out-of-State Gas		165	163	145	137	140	15
16		Subtotal	165	163	145	137	140	
17	Underground Storage Withdrawal		0	0	0	0	0	17
18	TOTAL GAS SUPPLY TAKEN		165	163	145	137	140	18
LINE	**REQUIREMENTS FORECAST BY END-USE**							
1	CORE	Residential	0	0	0	0	0	1
2	CORE/NONCORE	Commercial	0	0	0	0	0	2
3	CORE/NONCORE	Industrial	0	0	0	0	0	3
4		Subtotal	0	0	0	0	0	4
5	NONCORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	165	163	145	137	140	7
8		Subtotal	165	163	145	137	140	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	0	0	0	0	13
14		Subtotal-END USE	165	163	145	137	140	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL THROUGHPUT		165	163	145	137	140	16
	TRANSPORTATION AND EXCHANGE							
17	CORE	All End Uses	0	0	0	0	0	17
18	NONCORE	Commercial/Industrial	0	0	0	0	0	18
19		Non-EOR Cogeneration	0	0	0	0	0	19
20		EOR Cogen. & Steaming	0	0	0	0	0	20
21		Electric Utilities	165	163	145	137	140	21
22		Subtotal-RETAIL	165	163	145	137	140	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		165	163	145	137	140	24
	CURTAILMENT (RETAIL & WHOLESALE)							
25		Core	0	0	0	0	0	25
26		Noncore	0	0	0	0	0	26
27		TOTAL-Curtailment	0	0	0	0	0	27
28	REFUSAL		0	0	0	0	0	28

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
FORECAST YEARS 2011-2025
AVERAGE TEMPERATURE YEAR

LINE	GAS SUPPLY AVAILABLE		2011	2012	2015	2020	2025	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2		California Offshore - POPCO/PIOC	0	0	0	0	0	2
3		El Paso Natural Gas Co.	0	0	0	0	0	3
4		Transwestern Pipeline Co.	0	0	0	0	0	4
5		Kern /Mojave	146	146	146	0	0	5
6		PGT/PG&E	0	0	0	0	0	6
7		Other	0	0	0	0	0	7
8	TOTAL Out-of-State Gas		146	146	146	0	0	8
9		Subtotal	146	146	146	0	0	9
10	Underground Storage Withdrawal		0	0	0	0	0	10
11	TOTAL GAS SUPPLY AVAILABLE		146	146	146	0	0	11
	GAS SUPPLY TAKEN							
12	California Source Gas		0	0	0	0	0	12
	Out-of-State Gas							
13		Pacific Interstate Companies	0	0	0	0	0	13
14		Other Out-of-State	145	144	156	174	207	14
15	Total Out-of-State Gas		145	144	156	174	207	15
16		Subtotal	145	144	156	174	207	
17	Underground Storage Withdrawal		0	0	0	0	0	17
18	TOTAL GAS SUPPLY TAKEN		145	144	156	174	207	18

LINE	REQUIREMENTS FORECAST BY END-USE		2011	2012	2015	2020	2025	LINE
1	CORE	Residential	0	0	0	0	0	1
2	CORE/NONCORE	Commercial	0	0	0	0	0	2
3	CORE/NONCORE	Industrial	0	0	0	0	0	3
4		Subtotal	0	0	0	0	0	4
5	NONCORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	145	144	156	174	207	7
8		Subtotal	145	144	156	174	207	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	0	0	0	0	13
14		Subtotal-END USE	145	144	156	174	207	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL THROUGHPUT		145	144	156	174	207	16
	TRANSPORTATION AND EXCHANGE							
17	CORE	All End Uses	0	0	0	0	0	17
18	NONCORE	Commercial/Industrial	0	0	0	0	0	18
19		Non-EOR Cogeneration	0	0	0	0	0	19
20		EOR Cogen. & Steaming	0	0	0	0	0	20
21		Electric Utilities	145	144	156	174	207	21
22		Subtotal-RETAIL	145	144	156	174	207	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		145	144	156	174	207	24
	CURTAILMENT (RETAIL & WHOLESALE)							
25		Core	0	0	0	0	0	25
26		Noncore	0	0	0	0	0	26
27		TOTAL-Curtailment	0	0	0	0	0	27
28	REFUSAL		0	0	0	0	0	28

2006 CALIFORNIA GAS REPORT

GLOSSARY

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Average Day (Operational Definition)

Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature year

Long-term average recorded temperature.

BCF

Billion cubic feet of gas.

BTU (British Thermal Unit)

Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water one degree Fahrenheit. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

California-Source Gas

1. Regular Purchases – All gas received or forecast from California producers, excluding exchange volumes. Also referred to as Local Deliveries.
2. Received for Exchange/Transport – All gas received or forecast from California producers for exchange, payback, or transport.

CEC

California Energy Commission.

CNG (Compressed Natural Gas)

Fuel for natural gas vehicles, typically natural gas compressed to 3000 pounds per square inch.

Cogeneration

Simultaneous production of electricity and thermal energy from the same fuel source. Also used to designate a separate class of gas customers.

Cold Temperature Year

Cold design-temperature conditions based on long-term recorded weather data.

Commercial (SoCalGas & SDG&E)

Category of gas customers whose establishments consist of services, manufacturing nondurable goods, dwellings not classified as residential, and farming (agricultural).

Commercial (PG&E)

Non-residential gas customers not engaged in electric generation, enhanced oil recovery, or gas resale activities with usage less than 20,800 therms per month.

Company Use

Gas used by utilities for operational purposes, such as fuel for line compression and injection into storage.

Core Aggregator

Individuals or entities arranging natural gas commodity procurement activities on behalf of core customers. Also, sometimes known as an Energy Service Provider (ESP), a Core Transport Agent (CTA), or a Retail Service Provider (RSP).

Core customers (SoCalGas & SDG&E)

All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC.

Core Customer (PG&E)

All customers with average usage less than 20,800 therms per month.

Core Subscription

Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

CPUC

California Public Utilities Commission.

Cubic Foot of Gas

Volume of natural gas, which, at a temperature of 60º F and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

Curtailment

Temporary suspension, partial or complete, of gas deliveries to a customer or customers.

EG

Electric Generation (including cogeneration) by a utility, customer, or independent power producer.

Energy Service Provider (ESP)

Individuals or entities engaged in providing retail energy services on behalf of customers. ESP’s may provide commodity procurement, but could also provide other services, e.g., metering and billing.

Enhanced Oil Recovery (EOR)

Injection of steam into oil-holding geologic zones to increase ability to extract oil by lowering its viscosity. Also used to designate a special category of gas customers.

Exchange

Delivery of Gas by one party to another and the delivery of an equivalent quantity by the second party to the first. Such transactions usually involve different points of delivery and may or may not be concurrent.

Exempt Wholesale Generators (EWG)

A category of customers consuming gas for the purpose of generating electric power.

FERC

Federal Energy Regulatory Commission.

Gas Accord

The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by PG&E in March 1998. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005.

Key features of the Gas Accord structure include the following: unbundling of PG&E's gas transmission service and a portion of its storage service; placing PG&E at risk for transmission service and a portion of its storage service; placing PG&E at risk for transmission and storage costs and revenues; establishing firm, tradable transmission and storage rights; and establishing transmission and storage rates.

Gas Sendout

That portion of the available gas supply that is delivered to gas customers for consumption, plus shrinkage.

Heating Degree Day (HDD)

A heating degree day is accumulated for every degree Fahrenheit the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65ºF; PG&E 60ºF). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50ºF average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Industrial (SoCalGas & SDG&E)

Category of gas customers who are engaged in mining and in manufacturing durable goods.

Industrial (PG&E)

Non-residential customers not engaged in electric generation, enhanced oil recovery, or gas resale activities using more than 20,800 therms per month.

LDC

Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)

Natural gas that has been super cooled to -260° F (-162° C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

MMBTU

Million British Thermal Units. One MMBTU is equals to 10 therms or one dekatherm.

MMCF

Million cubic feet of gas.

MMCF/DAY

Million cubic feet of gas per day.

NGV (Natural Gas Vehicle)

Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

Noncore Customers

Commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements.

Non-Utility Served Load

The volume of gas delivered directly to customers by an interstate or intrastate pipeline or other independent source instead of the local distribution company.

Off-System Sales

Gas sales to customers outside the utility's service area.

Out-Of-State Gas

Gas from sources outside the state of California.

Priority of Service (SoCalGas & SDG&E)

In the event of a curtailment situation, utilities curtail gas usage to customers based on the following end-use priorities:

1. Firm Service – All noncore customers served through firm intrastate transmission service, including core subscription service.
2. Interruptible – All noncore customers served through interruptible intrastate transmission service, including inter-utility deliveries.

Priority of Service (PG&E)

In the event of a curtailment situation, PG&E curtails gas usage to customers based on the following end-use priorities:

1. Core Residential
2. Non-residential Core
3. Noncore using firm backbone service (including UEG)
4. Noncore using as-available backbone service (including UEG)
5. Market Center Services

PSIA

Pounds per square inch absolute. Equal to gauge pressure plus local atmospheric pressure.

Purchase from Other Utilities

Gas purchased from other utilities in California.

Requirements

Total potential demand for gas, including that served by transportation, assuming the availability of unlimited supplies at reasonable cost.

Resale

Gas customers who are either another utility or a municipal entity that, in turn, resells gas to end-use customers.

Residential

A category of gas customers whose dwellings are single-family units, multi-family units, mobile homes or other similar living facilities.

Short-Term Supplies

Gas purchased usually involving 30-day, short-term contract or spot gas supplies.

Spot Purchases

Short-term purchases of gas typically not under contract and generally categorized as surplus or best efforts.

Storage Banking

The direct use of local distribution company gas storage facilities by customers or other entities to store self-procured commodity gas supplies.

Storage Injection
Volume of natural gas injected into underground storage facilities.

Storage Withdrawal
Volume of natural gas taken from underground storage facilities.

Supplemental Supplies
A utility's best estimate for additional gas supplies that may be realized, from unspecified sources, during the forecast period.

System Capacity or Normal System Capacity (Operational Definition)
The physical limitation of the system (pipelines and storage) to deliver or flow gas to end-users.

System Utilization or Nominal System Capacity (Operational Definition)
The use of system capacity or nominal system capacity at less then 100 percent utilization.

Take-or-Pay
A term used to describe a contract agreement to pay for a product (natural gas) whether or not the product is delivered.

Tariff
All rate schedules, sample forms, rentals, charges, and rules approved by regulatory agencies for used by the utility.

TCF
Trillion cubic feet of gas.

Therm
A unit of energy measurement, nominally 100,000 BTUs.

Total Gas Supply Available
Total quantity of gas estimated to be available to meet gas requirements.

Total Gas Supply Taken
Total quantity of gas taken from all sources to meet gas requirements.

Total Throughput
Total gas volumes passing through the system including sales, company use, storage, transportation and exchange.

Transportation Gas
Non-utility-owned gas transported for another party under contractual agreement.

UEG

Utility electric generation.

Unaccounted-For

Gas received into the system but unaccounted for due to measurement, temperature, pressure, or accounting discrepancies.

Unbundling

The separation of natural gas utility services into its separate service components such as gas procurement, transportation, and storage with distinct rates for each service.

WACOG

Weighted average cost of gas.

Wholesale

A category of customer, either a utility or municipal entity, that resells gas.

2006 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

The following utilities have been designated by the California Public Utilities Commission has respondents in the preparation of the California Gas Report.

- Pacific Gas and Electric Company
- San Diego Gas and Electric Company
- Southern California Gas Company

The following utilities also cooperated in the preparation of the report.

- City of Long Beach Gas and Oil Department
- City of Los Angeles Department of Water and Power
- Sacramento Municipal Utilities District
- Southwest Gas Corporation

A statewide committee have been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Richard Hendrix (Chairperson) – PG&E
- Jasmin Ansar – PG&E
- Gino Beltran – LADWP
- Jamie Cattanach – Southwest Gas
- Herb Emmrich – SoCalGas
- Glen Holland – SDG&E
- Loan Nguyen - SoCalGas
- Ginger Shugart – City of Long Beach

Observers

- Wendy Phelps – CPUC Energy Division
- William Wood – CEC

RESERVE YOUR SUBSCRIPTION

2007 CALIFORNIA GAS REPORT – SUPPLEMENT

Southern California Gas Company
2007 CGR Reservation Form
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249
Fax: (213) 244-4957

- ❑ Send me a 2007 CGR Supplement
- ❑ New subscriber
- ❑ Change of address

Company Name: ____

C/O: ____

Address: ____

City: ____________________ State: ______________ Zip: __________

Phone: (_____) _________________ Fax: (_____) _______________

Also, please visit our website at: www.socalgas.com
www.sdge.com

RESERVE YOUR SUBSCRIPTION

2007 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2007 CGR Reservation Form
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177
Fax: (415) 973-6272

- ❑ Send me a 2007 CGR Supplement
- ❑ New subscriber
- ❑ Change of address

Company Name: ____

C/O: ____

Address: ____

City: ___________________ State: ______________ Zip: __________

Phone: (_____) _________________ Fax: (_____) _______________

Also, please visit our website at: www.pge.com